PB89-161772

Advanced Utility Simulation Model Analytical Documentation State Level Model (Version 1.0)

Illinois Univ. at Urbana-Champaign

Prepared for

Environmental Protection Agency
Research Triangle Park, NC

Jan 89

U.S. Department of Commerce
National Technical Information Service
NTIS

PB89-161772

EPA/600/8-88/071a
January 1989

ADVANCED UTILITY SIMULATION MODEL ANALYTICAL DOCUMENTATION STATE LEVEL MODEL (VERSION 1.0)

by

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EPA Cooperative Agreement CR808514

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NATIONAL TECHNICAL INFORMATION SERVICE
SPRINGFIELD, VA. 22161

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

1. REPORT NO EPA/600/8-88/071a	2.	3. RECIPIENT'S ACCESSION NO. PB89 161772/AS
4. TITLE AND SUBTITLE Advanced Utility Simulation Model, Analytical Documentation, State Level Model (Version 1.0)		5. REPORT DATE January 1989
		6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) James J. Stukel (Group Leader)		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS University of Illinois at Urbana-Champaign College of Engineering 901 South Mathews Avenue Urbana, Illinois 61801		10. PROGRAM ELEMENT NO. 11. CONTRACT/GRANT NO. CR808514
12. SPONSORING AGENCY NAME AND ADDRESS EPA, Office of Research and Development Air and Energy Engineering Research Laboratory Research Triangle Park, NC 27711		13. TYPE OF REPORT AND PERIOD COVERED Final; 9/80 - 8/85 14. SPONSORING AGENCY CODE EPA/600/13

15. SUPPLEMENTARY NOTES AEERL project officer is Larry G. Jones, Mail Drop 62, 919/541-7716.

16. ABSTRACT
The report is one of 11 in a series describing the initial development of the Advanced Utility Simulation Model (AUSM) by the Universities Research Group on Energy (URGE) and its continued development by the Science Applications International Corporation (SAIC) research team. The AUSM is one of four stationary source emission and control cost forecasting models developed by EPA for the National Acid Precipitation Assessment Program (NAPAP). The AUSM projects air pollution emissions (SO2 and NOx), generating technology types and costs of operation, and combinations of fuels and emission control technologies to simultaneously meet electric demand and emission constraints on a least cost basis for each year through 2010. Thirteen electric demand regions are simulated, and output is provided for each of the 48 contiguous states. The initial version of AUSM, Version 1.0, was delivered by URGE in November 1984 and August 1985. Further development of the AUSM by SAIC between 1985 and 1988 has resulted in the development of Versions 2.0 and 3.0. Reports describing these revisions by SAIC to the initial Version 1.0 of AUSM are also part of this series.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Pollution	Sulfur Dioxide	Pollution Control	13B	07B
Utilities	Nitrogen Oxides	Stationary Sources		
Emission	Fuels		14G	21D
Cost Analysis	Electrical Power Demand		14A	
Simulation				20C
Forecasting	Mathematical Models			12A

18. DISTRIBUTION STATEMENT Release to Public	19. SECURITY CLASS (This Report) Unclassified	21. NO. OF PAGES 578
	20. SECURITY CLASS (This page) Unclassified	22. PRICE

EPA Form 2220-1 (9-73)

NOTICE

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ABBREVIATIONS

ITEM	DESCRIPTION
afudc	Allowance for funds used during construction
AUSM	Advanced Utilities Simulation Model
Btu	British thermal units (1 Btu = 1.055 kJ)
Ca/S	Calcium to sulfur ratio
CF	Capacity factor
FIPS	Federal Information Processing Standard
HHV	Higher heating value
itc	Investment tax credit
kJ	Kilojoule (1 kJ = 10^7 ergs)
kW	Kilowatt (1 kW = 1 kJ)
kWh	Kilowatt hour
lb	Pound (1 lb = 0.454 kg)
LDC	Load Duration Curve
LIMB	Lime Injection Multi-stage Burner
mi	Mile (1 mi = 1.609 km)
mil	One Thousandth of a dollar (1 mil = $0.001)
MMBtu	Million British thermal units (MMBtu = 1.055 x 10^6 kJ)
MPMS	Multi-period, Multi-state
MW	Megawatts
MWh	Megawatt hours
NCSM	National Coal Supply Model
NO_x	Nitrogen oxides
NSPS	New Source Performance Standard (1971)
SAIC	Science Applications International Corporation
SO_2	Sulfur dioxide
RNSPS	Revised New Source Performance Standard (1979)
SAS	SAS Institute, Inc., developer of a series of data analysis and management packages for the computer
SIP	State Implementation Plan
ton	Ton (1 ton = 1016 kg)
URGE	Universities Research Group on Energy
US	United States
XMP	FORTRAN based linear programming package

ACKNOWLEDGEMENTS

The Environmmental Protection Agency (EPA) wishes to acknowledge the considerable work by the Universities Research Group on Energy (URGE) research team led by James J. Stukel, that contributed to this document. The efforts of the following chapter/appendix authors are recognized:

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Appendix A. Electric Utility Unit Inventory

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Appendix B. The Coal Reserve Data Base

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Appendix C. Coal Cleaning Methodology

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EPA also acknowledges the work of Robert T. Lassinger, Science Applications International Corporation, in editing the final text of this document.

1. INTRODUCTION AND OVERVIEW

by
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The Advanced Utility Simulation Model (AUSM) is a policy tool designed to analyze the implications for the U.S. electric utility sector of alternative strategies for reducing air pollutant emissions in the generation of electricity. The need for such a model was emphasized by an expanded effort within the sponsoring agency, the U.S. Environmental Protection Agency (EPA), other federal agencies directed toward acid rain mitigation and by an impending congressional review of the Clean Air Act.

The AUSM developmental work was carried out through a cooperative agreement between EPA and the University of Illinois at Urbana-Champaign; the agreement was initiated in September 1980. The arrangement included subcontracts with Cornell University and Carnegie-Mellon University. The researchers performing the work were known collectively as the Universities Research Group on Energy (URGE)[1]

The state-level AUSM has been completed, tested and implemented in the public domain. This state-of-the-art model operates at the state level, with special emphasis on the role of coal for the generation of electricity. The model is used to analyze critical policy alternatives concerned with the mitigation of acid rain and other air pollution issues. The AUSM was designed originally to deal with the policy strategies listed in Table 1-1. However, the model is also able to deal with many other strategies and issues.

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[1] The URGE researchers were led by the author of this chapter, James J. Stukel, Professor of Civil Engineering and Mechanical Engineering and Director, Public Policy Program, College of Engineering, University of Illinois at Urbana-Champaign.

Table 1-1
STRATEGIES: REGIONAL EMISSION CEILING POLICY FOCUS

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1. Technical Regulatory Changes: Absolute Emission Limitations

    1.1 By state
    1.2 By region
    1.3 By generating unit
    1.4 By type of unit (SIP and NSPS)

        1.4.1 Changes in averaging times of SIP units
        1.4.2 Redefinition of plant modification
        1.4.3 SIP rollback
        1.4.4 Nonenforcement of SIPs
        1.4.5 Emission charges-transferable discharge permits

2. Financial Regulatory Changes

    2.1 Revenue-setting policies
    2.2 Corporate income tax investment incentives
    2.3 Pollution control costs

        2.3.1 Changing investment tax credit
        2.3.2 Rate base treatment, tax depreciation
        2.3.3 Interest rates

3. Control Options

    3.1 Coal cleaning: a specific level of cleaning for all coals above a given sulfur content
    3.2 Coal blending
    3.3 Low-sulfur coal
    3.4 Local coal use
    3.5 Nuclear fuel
    3.6 Oil and gas fuel

4. Technology-Based Regulatory Changes

    4.1 Wet and dry FGD systems
    4.2 NOx control technologies
    4.3 Particulate control technologies: electrostatic precipitators and fabric filters

5. System Operating Performance and Utility Behavior-Based Regulatory Changes

    5.1 Least emission dispatch
    5.2 Shortening or prolonging of plant lifetime
    5.3 Utility strategy for least-cost compliance with regional emission ceilings

6. Least-Cost Combinations of Fuel and Technology Choice

1.1 Background

Several models for utility sector analysis have been used in the past. Most of them have proven to be inadequate in one or more of five important respects. First, their basic designs did not provide an adequate balance of detail between coal supply and the utility sectors, which is needed for an accurate assessment of economic and other important impacts of air pollution control strategies currently under consideration. Second, the analytical abilities of these models in specific areas of importance were limited and/or outdated. Third, they were time-consuming and expensive to operate. Fourth, these models were poorly documented or undocumented. Finally, many were proprietary and unavailable for use by anyone other than the model developer.

The AUSM project was established explicitly to deal with many of these shortcomings and to produce several improvements in the state-of-the-art in modeling the electric utility industry. A staged approach was adopted for developing the advanced model. The effort began with a one-company, annually recursive model (see Section 1.2) and progressed to a state-level model. The state-level model was completed and transferred to EPA. The work was then extended to the development of a national-level model. This report deals with the analytical capability and conceptual design of the state-level model, many elements of which formed the basis of the work on the national-level model.[2]

1.2 Analytical Capabilities of the State-Level AUSM

A major new feature of the AUSM is its annually recursive interaction among the computer modules simulating electricity demand, pollution control, dispatching, capacity planning, and utility financial status. Currently available models run in a "block recursive" mode. That is, the above functions are projected sequentially into the future without any feedback linkages between them. In this type of operation, the level of electricity demand and the mix of types of generating units (e.g., coal versus nuclear) are specified exogenously and are unaffected by the implications, primarily economic and demographic, of the control scenarios utilized. In an era of declining demand growth and difficult financial conditions for utilities, these unrealistic assumptions are considered inadequate.

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[2] For a report of the initial AUSM development work, see Reference 3.

The annually recursive capability incorporates an endogenous demand forecast, which can be adjusted up or down by the user, who specifies changes in the economic growth rate. As the simulation proceeds year by year into the future, the interactions between changing construction or operating costs, electricity prices and electricity demand are captured explicitly. The annual recursive model provides an interactive loop between each module, driven by a set of iterative steps between demand and finance. An estimate of electricity demand by major classes of customer is made for a given year. This estimate is translated into a forecast of revenues received by the utilities. The financial module receives base-year and historical plant data, operating costs and pollution control investments to compute total revenue requirements for the investor-owned electric utilities. Total revenue received is reconciled with revenue requirements in the rate rescheduling component of the module to ensure that utility companies receive the rate of return specified by regulatory agencies. Integration of the demand and financial modules means that the specified rate schedules are consistent with the financial viability of the electric utility companies. Using these more realistic demand projections, the other modules interact to plan capacity and dispatch load so as to meet demand under a specific regulatory scenario. Each successive year is run in this recursive fashion, i.e., responding to the preceding year's behavior and affecting the behavior of the following year. This procedure maintains internal consistency among the modules during the simulation run.

The following description of the state-level AUSM discusses the operating characteristics of the model. Although all of the major features are explored, the features that are substantial improvements over existing models are described more fully. The discussion is organized around the analytical capabilities of each modular component of the AUSM, and follows the order of the succeeding chapters in this documentation volume: electricity demand, finance, coal supply, pollution control, dispatching and capacity planning. This report also includes a description of the inventory of electrical generating units developed for the project (Appendix A), the coal reserves data base (Appendix B) and the methodology used to simulate coal cleaning (Appendix C)[3].

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[3] Additional volumes in the state-level documentation series include reports on program documentation and on future maintenance of the model.

1.2.1 Electricity Demand Analysis

The AUSM has been designed using a state as the basic spatial unit and a year as the temporal unit. As noted earlier, the model operates in an annually recursive fashion, implying that all modules are run in sequence for each state and each year. The underlying reason for doing this is to provide a more realistic representation of how electric utilities operate by making major feedback mechanisms explicit in the model. Projected future levels of demand in most other models are treated as predetermined values that are adjusted infrequently for a given state. In actual practice, projections of demand are modified over time in response to changes in economic conditions. The causes of these new conditions—such as changing expectations about economic growth--may be external to the utility industry. The changes may also be determined internally, within the utility company. Examples of these latter changes include the consequences of adopting various policies for meeting different emission standards, as well as changing the methods by which the associated costs are passed on to customers.

For any given state and year, the demand module determines some of the initial conditions used in other modules because its output is fundamental to projected utility operating levels. Thus, operation of the demand module signifies the beginning of each successive year. The information determined within the demand module can be summarized as follows:

1. The level of energy and the peak load demanded in the current year, net of interstate transfers, are determined for the dispatching module.

2. Total revenue and the net cost of interstate transfers are determined for the financial module.

3. Projected levels of future demand are determined for the planning module.

4. Information about the levels of demand for electricity and other fuels is determined and saved for subsequent use in the energy and employment impacts module [4].[4]

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[4] The energy and employment impacts module [4], which has no analog in existing models, estimates the direct employment effects on the coal industry and the electric utility sector that result from a given scenario. Other secondary effects are also calculated. The module is structured around a simplified input-output model of the U.S. economy and will function as an optional postprocessor to the AUSM. Because the module applies only to a national-level analysis, it is not discussed in this report, which is concerned with the state-level model.

Some of the factors affecting electricity demand are specified externally; others are determined within the complete model. The most important input information determined within the model relates to revenue requirements; it includes the allowed return on capital and a breakdown of operating costs. This financial information is used to determine the rates charged to different classes of customers in the following year.

Much of the external information used in the demand module relates to inputs for the demand equations. There are two major components: the first gives the prices of primary fuels; the second, economic and demographic data. Efforts have been made to reduce the amount of information needed with both types of inputs. For example, values of an input are provided for a few specified years, and intermediate values are computed by interpolation. Furthermore, much of the input information is shared with other modules. The dispatching module, for example, uses the same prices of fuels as the demand module, and much of the economic information is used by the energy and employment impacts module. Currently, information on the interstate transfers of power is provided externally, but much of this information will be determined within the overall model when states are grouped into dispatching regions, as proposed.

The basic demand data set covers the 48 contiguous states in the United States for the years 1964 through 1980. Some information for the first three years could not be obtained, and some information for 1980 is not yet available. Consequently, the sample period used for estimation is from 1967 through 1979. Documenting and checking the accuracy of the data base was a major effort.

The sources of data selected make it feasible to consider disaggregating demand into five customer sectors: residential, commercial, industrial, transportation, and electric utilities. Almost all of the final sales of electricity go to the first three sectors. Transportation is an important sector for oil use, but current electricity use in this sector is essentially zero in most states, and very small in the rest. The use of electricity by electric utilities accounts for all of the differences between the quantity of electricity generated and final sales. Thus, the most important "uses" in this sector relate to distribution losses and to interstate transfers of power. At the present time, demand equations have been developed for the residential, commercial, and industrial sectors. The demand for electricity in the transportation sector, if there is any, is treated as a fixed proportion of the quantity demanded in the commercial sector.

The main features of the demand module can be summarized in terms of the four major components:

1. *Update Rate Schedules.* The information from the financial model is used to set new rates for electricity in the different sectors.

2. *Demand Equations.* These rates are combined with externally provided information about the prices of primary fuels and economic conditions to predict the quantities of electricity and of primary fuels demanded in the different sectors for a given state in a particular year.

3. *Load Characteristics.* The sales of electricity to each sector are aggregated and modified to account for distribution and other losses, and for interstate transfers. Additional load characteristics, such as the system load factor, are specified so that the information passed to the dispatching module reflects generation and peak load net of transfers.

4. *Demand Projections.* A projection is made of the system load 10 years ahead of the current year. This information is used in the planning module to develop a construction plan for new generating facilities. It should be noted that this component of the demand module is designed to approximate the planning processes used by electric utilities, and the projection of demand is not derived directly from the demand equations.

If the model user wishes to specify a fixed electrical demand growth rate, the AUSM is designed to accommodate this request. The benefits of annual recursiveness are sacrificed by this decision. However, it provides a useful point of departure for comparing AUSM results with those obtained from other models.

1.2.2 Electric Utility Financial Analysis

Most existing financial models of the utility industry were constructed initially in the mid-1970s and have embodied in them tax, regulatory, and financial assumptions and conditions that do not reflect current practice. In existing models some of these assumptions may have been updated on a piecemeal basis, but there is great concern that no existing electric utility model reflects a comprehensive treatment of current conditions. In addition, these assumptions tend to be embedded in other models in a way that makes them difficult to evaluate or update.

The AUSM addresses this problem in several ways. First, the financial module is designed and documented in such a way that assumptions about tax, regulatory, or other financial conditions are apparent and easily updated. Second, a major effort has been undertaken to contact all state public utility commissions and determine their current practices toward utility finances and rates. Also, recent changes in tax laws that affect utilities have been incorporated. Finally, a detailed data base has been assembled that reflects accurately utility financial status in the base year, 1980.

The utility financial calculations in the AUSM are based on unit-level decisions concerning electricity generation, pollution control equipment, fuel selection, and other unit operating parameters. The results of these unit-level decisions are aggregated to the state level, where they are analyzed by the financial module.

The financial calculations compute a total revenue requirement for the electric utilities in a state by utilizing base-year and historical plant data, new construction costs from the planning module, and operating costs and pollution control investment from the dispatching and the pollution control modules. That year's revenue requirement goes to the demand module and its rate rescheduling component, where it helps determine the following year's demand and actual revenues. These revenues are used to compute financial accounts, income taxes, and certain financial statistics.

The module distinguishes 12 different categories of assets, including new and retrofitted pollution control equipment. It is designed to accept data on individual units, plants, or even aggregations of plants as long as the aggregations are of the same type of asset, come on-line in the same year, and (in the case of new plants) have the same construction period.

The major accounting variables for different forms of depreciation and for regulatory tax accounting are developed on an asset-by-asset basis. Thus, although the model is currently written at the state level and assumes that the state applies policies uniformly to all its utilities, with few modifications to the program. specific regulatory policy options could be linked to each asset in order to model a state with nonuniform policies or a region with more than one regulatory policy.

The financial calculations incorporate the provisions of the current tax law so that new assets entering service after December 31, 1980, are treated according to its provisions, while assets on-line before that date are treated under the old federal corporate income tax code. Current state regulatory practices, as determined from a review of state public utility commissions [5], are incorporated into the financial calculations.

A major advantage of the AUSM approach is that it reflects state-level activities. This is particularly important when dealing with state regulatory and/or environmental regulations.

1.2.3 Coal Supply Analysis

A number of improvements over existing models are envisioned in the treatment of coal supply within the AUSM. First, it has been recognized clearly that a fundamental tradeoff has always existed between the desire for extremely detailed representations of both the coal and utility sectors and the desire for a model that is computationally manageable. The ways in which this tradeoff has been dealt with in existing models are not entirely satisfactory. One approach maintains a great deal of detail in the coal supply sector but aggregates the utility sector. Another approach provides great detail in the utility sector but only at the cost of representing coal supply very poorly.

The AUSM approach to this problem is to provide detail in both the coal and utility sectors, but to break the coal supply model off as a separate component that does not need to be solved simultaneously with the detailed utility sector simulation. Supply and demand equilibrium models are not constructed. Rather, the cost of delivered coal is calculated independent of coal demand. The assumption is that supply is sufficiently large that prices are affected more by changes in mining, preparation, and transportation costs than by changes in demand. The coal module simulates costs of coal production, washing, and transportation, and computes delivered least-cost coal as a function of time. The utility-related modules then use these costs to perform the annually recursive simulations. Compatibility between demand and delivered costs is assured if depletion is not a factor. In the state-level model, depletion effects are neglected. In the national-level model, these effects will be dealt with directly.

The coal supply module estimates the price of coal delivered to each demand region. It is computed for 11 sulfur categories and three higher heating value categories for each time period. The calculation procedure identifies the combination of supply region, raw coal type, and cleaning technology yielding the least delivered cost.

All cost components vary over time according to user-specified escalation rates. Delivered prices are computed for 11 years during the period from 1980 through 2040; estimates for intervening years are obtained by interpolation. Coal prices are estimated for 30 years beyond the AUSM horizon so the model can take them into account when selecting coals for new power plants.

Minemouth costs can be estimated in two ways, at the option of the user. The first option is to use the econometric forecasts of minemouth costs developed by the U.S. Department of Agriculture (USDA) for 1980 through 1990, followed by user-specified escalation rates for the period beyond 1990 [6]. The forecasts are based on actual coal prices reported for over 76,000 shipments between 1973 and 1980.

The second option employs mine cost equations, together with data on the quantity and distribution of coal reserves in each supply region, and assumptions regarding the size distribution of the mines that would exploit these reserves. The state-level AUSM is based on the cost equations developed for nine model mines by the Energy Information Administration (EIA), U.S. Department of Energy, in connection with its 1981 annual report to Congress [7]. The coal supply module, however, is structured in a manner that allows other EIA mine costing algorithms to be used if desired. With only minor modifications, it will also be possible to insert econometrically based mine costing equations such as those developed by Zimmerman [8] for comparison with the engineering-based equations developed by EIA.

The existence of both near-term econometric and long-term model mine projections allows the AUSM to deal realistically with near-term market conditions as well as the factors that determine coal prices over the long term. The AUSM short-term coal supply projection capability is based on an extensive, detailed data base of current coal production and prices and current coal movements. This short-term capability will be linked to the standard long-term mine-costing approach so that the overall coal supply module will more accurately reflect "inertia" built into the current coal supply and transportation system. The mine costing algorithms used in the long-term analysis allow evaluations of the effects of escalation of major cost components (e.g., wages), as well as the effects of cost increases due to severance taxes or other policies.

Another major improvement over existing coal supply models is the incorporation of a detailed coal cleaning model into the AUSM coal supply module. The general objective of coal cleaning processes is to improve the value of the coal produced by reducing the presence of impurities such as ash, sulfur and moisture. The reductions are obtainable only at a cost, comprising both the cost of constructing and operating a processing plant and the cost of combustible material that is discarded along with the refuse from the preparation process.

The "washability" of a coal may be very loosely defined as the extent to which its properties can be enhanced without discarding large quantities of combustible material and incurring an exorbitant cost. Unfortunately, from the point of view of establishing a treatment of coal washing within a large systems model, the washability of U.S. coals varies significantly, both from one coal producing region to another and within regions. Even within coal seams, washability can vary from one location to another and in different layers of the seam.

The approach taken for the AUSM has been conditioned strongly by three factors:

1. The only consistent set of data referring to the washability of U.S. coals as a whole is contained in a data base built and maintained by the U.S. Bureau of Mines (BOM).
2. The washability of coal varies so greatly that the only satisfactory approach that can be taken is statistical.
3. The primary interest in coal washing within the context of the AUSM lies in its potential for removing sulfur from coal and hence reducing sulfur dioxide emissions.

The BOM data base contains washability data collected under laboratory conditions and therefore is not representative of the performance of actual process plant. Hence, a preparation plant model was built to take account of this factor. This model has two parts. The first adjusts washability data collected under ideal circumstances for actual plant conditions and determines the optimal mode of operation which will result in a specific enhancement of coal properties. The second part estimates the capital and operating costs of the various items of the processing plant. Physical capacities of the plant will depend on the particular mode of operation chosen in the first part of the model.

In order to simplify the large number of different processes, and the combinations of processes that are used in practice, four "generic" levels of preparation plant, with differing degrees of complexity, were defined. The most simple level involves crushing and screening and cannot achieve any significant levels of sulfur reduction in a run-of-mine coal. It is reasonable to assume that most bituminous coals receive at least this degree of preparation. The remaining three levels involve the use of processes such as jigging or heavy media separation in order to remove particles with high ash and sulfur contents.

For each of the three higher levels of preparation, the model was applied to each of the 710 coals currently in the BOM data base. The coal properties, costs, and yields associated with different degrees of sulfur removal were estimated and used to establish a data base of cleaned coal properties.

Since the ultimate aim was to develop a capability for estimating the washability properties of coal specified externally from a "reserves" data base, a series of functions representative of actual washability curves was set up. For each of several geographical regions, statistical techniques were employed to estimate the values of the coefficients in the functions, using as input the data base of cleaned coal properties.

This procedure resulted in a series of algorithms that could be used to estimate the washability properties of any U.S. coal given information on its geographical origin and run-of-mine properties. Although the washabilities of actual coals may vary considerably from those predicted by the set of algorithms, it is believed that they give a representative description of the washabilities of "average" or "typical" coals. The algorithms were subsequently used to "wash" the AUSM characteristic coals defined from the reserves data base.

In contrast to the AUSM approach, other models build in regional washing characteristics for highly aggregated coal deposits. These characteristics represent general trends only.

The final component in the coal supply module is a set of coal transportation costs linking each of the supply regions to the 48 demand regions. These origin-destination costs are computed for rail-water and rail-only routings using the USDA Transportation Analysis System, probably the most-detailed transportation network representation available. It is incorporated into the coal supply module in a manner that allows the analysis of the effects of changes in the system (e.g., escalation of various cost components) on future coal movements and prices.

1.2.4 Pollution Control Technology Analysis

The pollution control technology analysis uses a set of relatively simple economic models that have been developed to estimate the total capital cost and annual revenue requirements of several currently available systems for sulfur dioxide and particulate control at a new coal-fired power plant. Despite their computational simplicity, these models are sensitive to key coal, plant, economic, and regulatory parameters that affect capital and operating costs. They were developed by applying engineering analysis and statistical regression techniques to simplify and systematize the costs predicted by other detailed studies or models of major pollution control system components.

The objective of the economic models is to determine the effect of pollution control measures on the busbar costs of supplying a given amount of electricity. As used here, the difference between the gross generating capacity of a power plant and the net capacity delivered to consumers is the electrical capacity penalty due to pollution control. In general, a nominal or basic engineering design was first assumed for each technology (system component), and the cost of that design was determined from detailed studies or models reported by other investigators. Simpler models were then developed using regression analysis and other techniques to calculate costs for components of similar designs when pollutant emission constraints, coal characteristics, component size (or capacity), and economic criteria are varied.

The energy requirement of pollution abatement technology makes it necessary to also consider the economic value of power plant capacity used by environmental controls, which is thus unavailable to consumers. The model adopted for calculating the cost of this capacity is an exponential scaling model suggested by the work of Scherer [9], the Bechtel Corporation [10], and others [11,12]. The model parameters reflect the cost of a "base" plant with no sulfur dioxide or particulate controls, developed from a study summarizing recent cost estimates for U.S. power plants. They also include independent estimates of water pollution and thermal effluent control costs since these are normally required for new coal-fired power plants. Costs have been updated using the Handy-Whitman Construction Index [13]. Other base case cost estimates could be substituted, as appropriate.

The model of power plant variable costs was developed from data reported by Scherer [9] and Friedlander [14]. The model explicitly reflects the delivered price of fuel. All other variable costs are represented in constant proportion to the gross annual generation given by the product of capacity factor and gross plant capacity.

Dry collection of flyash is assumed to be achieved using either an electrostatic precipitator or a fabric filter. Various studies [15,16,17] suggest that the flange-to-flange capital cost of both types of devices scales principally with the physical collection area. This is the principal parameter in the models. A second term, dependent on plant capacity, reflects the added cost of ash-handling equipment.

For electrostatic precipitators, the capital cost equations were adopted from Research-Cottrell estimates [15], which are in substantial agreement with other estimates. The required removal efficiency is determined principally by the particulate emission constraint and coal ash content. Thus, the model is sensitive to both coal properties and environmental regulations.

For fabric filters, the models of total capital cost and total variable cost are also adapted from Research-Cottrell [15], whose results are in good agreement with other cost estimates. The total bag collection area is the flue-gas flow rate G, divided by the air-to-cloth ratio (A/C), an independent parameter of the model. The total variable cost of fabric filtration system is modeled in terms of the flue-gas flow rate and the bag replacement charge. The latter is a function of A/C but also may be specified by the user.

The most common method of flue gas desulfurization (FGD) in the United States is a wet scrubbing system employing limestone as the reagent. In developing the economic models reported here, extensive use has been made of the Tennessee Valley Authority (TVA) computer models [18] for detailed cost estimation of lime or limestone systems; these models have been compared with other models for estimating FGD system costs. All results suggest that the direct capital cost of limestone systems can be estimated reliably in terms of the maximum expected values of the flue-gas volumetric flow rate and the mass rate of sulfur dioxide removal. The gas flow rate depends principally on the gross power plant size and heat rate. If only partial scrubbing is employed, the gas flow rate through the scrubber also depends on the fraction of total gas bypassed. The design mass removal rate of sulfur dioxide depends principally on boiler type, coal composition, and air pollution emission constraints. FGD system capital costs were determined for two subsystems: reagent handling and individual scrubber trains.

The AUSM scrubber cost equations were determined from a multiple regression analysis of costs predicted by the TVA model over a wide range of power plant sizes, heat rates, and coal characteristics. Scrubber configuration with and without forced oxidation was considered, as were different design values of limestone stoichiometry, scrubber liquid-to-gas ratio, and number of spare trains to enhance FGD system reliability.

Simplified models of total variable cost were also developed using multiple regression analysis of results from the TVA program. Here too the flow rate of flue gas and the mass removal rate of sulfur dioxide (based on the annual average capacity factor rather than on maximum or design capacity) were the key determinants of variable cost, in addition to the reagent cost, which is directly proportional to the mass of sulfur dioxide removed.

The capital cost of a solid waste disposal system can be expected to depend principally on the mass rate of waste generation. The cost of land is another factor that has been modeled separately for accounting convenience. The capital costs are scaled on full-capacity sulfur dioxide, and ash removal rates though the assumed lifetime volume of solids collected reflect a 30-year life with a nominal declining capacity factor. Models have been developed for three options: forced oxidation, chemical sludge fixation, and the simple untreated ponding of solid wastes. The capital models were developed using multiple regression analysis of the solid waste disposal costs reported by TVA. The total variable cost of solid waste disposal is modeled on the basis of average annual sulfur dioxide and flyash removal rates, plus the cost of labor, which is a function principally of power plant size.

Dry FGD systems on coal-fired power plants are only now beginning to emerge at a commercial scale in the U.S., hence, detailed and reliable data on system design, performance and costs are not as widely available as for wet FGD systems. In particular, the use of dry FGD systems thus far has been limited to low sulfur western coal applications and moderate SO_2 removal efficiencies, where the economics of dry FGD is most favorable. Though design studies also are available for high sulfur coal applications and high SO_2 removal efficiencies, full-scale data remain lacking. Nonetheless, the analytical model of a dry FGD system incorporated in the AUSM may be easily used in sensitivity studies to explore the consequences of alternative assumptions regarding the nature or impacts of future developments.

Development of the dry FGD model was based on a number of recent studies. Tennessee Valley Authority (TVA) data and assumptions were used as extensively as possible to maintain consistency between the wet and dry FGD system models in the AUSM. However, care was taken to insure that model parameters could reflect alternative design and cost assumptions as well.

In contrast to wet limestone FGD, a dry lime system produces a dry solid waste instead of a thickened sludge. This solid waste can be used as a partial recycle slurry to reduce alkali reagent costs.

Reduction of NO_x emissions in new or existing units may in principle be achieved through combustion modifications and/or flue gas treatment (FGT) technology. In practice, FGT systems achieving high (80% or more) levels of NO_x removal have not yet been commercially demonstrated in the U.S., and are not widely regarded as a near-term option for NO_x control. Their high cost also precludes their likely consideration under current regulatory requirements. Combustion modification techniques, on the other hand, may be capable of reducing NO_x emissions by up to about 60 percent, and are the principal methods currently being considered for NO_x control. Such techniques have already been widely implemented on new fossil fuel boilers, and also – though to a much lesser extent – on existing units. Retrofit applications lie primarily with oil and gas-fired units, with relatively little experience on coal-fired facilities.

Combustion modifications currently in use are primarily based on lowering the oxygen content in the primary flame zone and, secondarily, on lowering peak flame temperature. There are four general control methods: low excess air (LEA), flue gas recirculation (FGR), low NO_x burners (LNB) and off-stoichiometric combustion (OSC).

The NO_x control options adopted for the AUSM consist of low-NO_x burners and overfire air, which appear to be the most viable and widespread options for coal-fired plants. Overfire air with flue gas recirculation is also considered for oil and gas-fired units. Low excess air was not included as an option because the potential reduction (of about 10%) is small compared to variations in baseline data (up to a factor of two).

Because the level of NO_x reductions achievable through combustion modifications are not extremely well-defined (and often quite site-specific), the performance model adopted for the AUSM is a simple percent reduction of uncontrolled emissions for a given combination of boiler type and control method.

Economic models used in AUSM for NO_x control options are based on studies by Acurex and Combustion Engineering. Total capital and operating costs are proportional to plant size for large units (above 250 MW), and exhibit an exponential dependence on size for smaller units. Total capital costs for NO_x controls are quite small compared to other pollution control costs (e.g., on the order of 5% of the cost of an FGD system). Operating costs also often are negligible, though small operating costs may be incurred because of the need for additional combustion controls and increased maintenance. Similarly, a small energy penalty also is incurred with overfire air because of the increased fan load due to additional duct work.

Attention has recently refocused on direct limestone injection for use in conjunction with certain low NO_x combustion controls. Some of the combustion modifications which lead to reduced NO_x formation, such as reducing peak flame temperature and increasing coal residence time, also provide an improved environment for the reaction of limestone and SO_2. Research has centered around combining direct limestone injection with new multistaged low-NO_x burners (LIMB) with the goal of producing a minimum of 50% SO_2 removal and 70% NO_x removal.

The relationship between reagent molar stoichiometry (RMS) and SO_2 removal efficiency is not well defined for LIMB. It is known that SO_2 removal efficiency will depend on such variables as coal properties, boiler firing conditions, limestone reactivity, limestone fineness and limestone injection scheme, as well as reagent stoichiometry. However, the precise role of these factors is not yet well understood. EPA's goal is to achieve 50% SO_2 removal at a reagent molar stoichiometry (MSR) of 2.0. In a recent LIMB design study by Combustion Engineering, the MSR was varied from 1.0-4.0 while specifying a constant removal of 50%. TVA specified an MSR of 3.0 for 50% removal in their design study. Due to this uncertainty in the data, the performance model selected for the AUSM is a constant stoichiometry applicable to a specified SO_2 removal efficiency (rather than a functional relationship such as assumed for wet or dry FGD systems). A conservative default value of MSR = 3 at 50% SO_2 removal is used in the AUSM. However, the MSR and the resultant removal efficiency are scenario variables which may be modified as better information becomes available, or tested in sensitivity analyses. The NO_x removal efficiency for LIMB is set at a default value of 50 percent, the same value assumed for low-NO_x burners.

The LIMB capital cost model for the AUSM is based on four system modules: (1) reagent material handling and preparation, (2) boiler modifications, (3) particulate removal, and (4) waste disposal. With the exception of the boiler modification costs, AUSM models for other model components were utilized to estimate LIMB capital costs.

In carrying out state-level analyses, the AUSM abatement decisions are made at the generating unit level. Therefore, there is no ambiguity about either the environmental regulation or the state regulatory financial conditions that apply to the unit.

Aggregated models currently in use are unable to sort out the influence of environmental policy issues on individual units. Some of these models, for example, aggregate existing plants into a series of categories which are specified by the user. Each of these categories is treated as a single unit with respect to fuel use, dispatching, environmental control calculations, and the like. The scrubber cost calculations include full or partial scrubbing but do not include unit-specific data, for example, capacity and heat rate. In doing policy analysis at this highly aggregated level, it is difficult to capture accurately the economic conditions associated with utility environmental regulations. Also, this level of aggregation means that environmental regulations cannot be examined in as much detail, nor can the implications of these regulations for individual units. Finally, when the aggregation is carried out not only over plants but over multistate regions, there is considerable ambiguity as to how to treat state regulatory commission practices regarding the pass through of pollution control costs to the consumer and other such regulated parameters. It has been suggested that aggregation procedures can lead to a 3 million ton overestimate of current sulfur dioxide emissions [2].

1.2.5 Dispatching Analysis

Dispatching decisions can be viewed in three contexts, or perspectives. The first context in which electric utilities are examined is over extended time horizons, 20 years or more into the future, and extended geographical areas, encompassing many states. This perspective is called multiple region-multiple period (MRMP). The MRMP perspective is necessary for examining macro-level, interregional activities such as remote plant siting and interregional exchanges of energy. Of course, this perspective will not provide a detailed picture.

The second context is over extended time horizons but for only a single region. It is called the single region-multiple period (SRMP) perspective. This context is necessary for examining long-term activities that are specific to a region—for example, the planning of new generating facilities in a state over an extended horizon. The picture from this perspective, of course, will not be as broad as from the MRMP perspective, but the detail will be finer.

The third context, the single region-single period (SRSP) perspective, extends over only one period and one region. This perspective is necessary to obtain the most detailed picture, which is required by recursive portions of the AUSM. The SRSP perspective is used in the state-level AUSM.

A major characteristic of the dispatching module is its contextual compatibility. That is, the methodology applies to all three of the contexts from which electric utility operations are examined. The module also has procedural compatibility: its methodology meshes with the methodologies used in other AUSM modules, particularly in terms of fidelity, data requirements, and the production of data. The module also handles constraints systematically, so that it can accommodate large numbers of constraints in such areas as regional emissions and the availability of fuels. Moreover, the module is flexible enough to allow the addition of new constraints and decision variables as well as the deletion of old constraints and variables.

Various dispatching algorithms were examined to achieve the characteristics noted above. In particular, heuristics (merit ordering), linear programming, quadratic programming, and nonlinear programming were examined. Linear programming was deemed to be the best choice for the module, although merit-order dispatching is also available at the option of the user.

The state-level AUSM dispatching module can examine problems in a single region-single period (SRSP) context—i.e., one state-one year. The module is designed to estimate either (1) the least-cost energy allocation subject to constraints on the amounts of various emissions or (2) the allocation that produces the fewest emissions of a selected pollutant while constraints are maintained on other pollutant emissions and on operating cost. Five assumptions are made in the formulation. First, it is assumed that the load duration curve can be approximated by discrete steps. Little information is available on the shapes of the load duration curves in the various states. Therefore, using a stepped approximation (even if the number of steps is small) does not compromise the fidelity of the input data. The second assumption is that delivery losses can be grouped and added to the demand. The transmission and distribution networks are not included in the model. In essence, this means that all the generating plants in the region are placed together at a single node with the net load. (This assumption will be relaxed in the MRMP context.)

The third assumption is that either the amount or the cost of interregional energy exchanges is known. If the amount is known, it is included in the net load duration curve. If the cost is known, then interregional transfers are modeled by another module. Under the fourth assumption, forced outages can be modeled by the derating procedure. The final assumption is that the fuel to be used in each generating plant is known. (The fuel is chosen by the pollution control module.)

The least-cost dispatching strategy for the state-level AUSM is found given the following formation: (1) the length of the period to be considered; (2) peak and average values of the net demand for power over the period (net demand is the sum of end-use demand, delivery losses, and scheduled exports); (3) characteristics of the generating plants available for dispatching to meet the demand; (4) the amount and average cost of energy available, if needed, from outside the region under consideration; and (5) the limits on sulfur dioxide, oxides of nitrogen, and particulates produced in the region. The basic variation is to minimize emissions of one of these pollutants while maintaining upper bounds on the other emissions and costs.

1.2.6 Capacity Planning Analysis

The AUSM capacity planning module is similar to existing planning and siting modules, but with important differences. The annually recursive nature of the AUSM dictated an entirely different structure for the planning module, but certain features of existing approaches were retained. Among these was a three-part capacity needs test (reserve margin, available capacity, and available energy) that required only minimal information about the states' load profiles. Another was the idea of "building toward" a specified mix of generating technologies. This conventional method of implementing this latter feature was discarded because its probabilistic basis yielded results that could not be reproduced from one run to the next; the AUSM approach achieves the same goal with reproducible results.

The heart of the AUSM planning module is the establishment and annual modification of the utility's construction schedule. This unique structure, embedded in the AUSM's annually recursive framework, simulates the utility's response to the evolving discrepancies between old demand forecasts (the basis for its current construction program) and new, revised forecasts based on the previous year's actual demand. The module operates at the individual plant level, advancing and deferring single plants as required. Construction cost outlays are tabulated so as to facilitate the calculation of interest during construction and of real escalation. A serious shortcoming of one conventional approach is its total reliance on user specification of the mix of generating technologies, plant retirement dates, and the schedule for conversion of oil- and gas-fired plants to coal. Economic optimization models, another approach, employ linear programming algorithms to deal with factors like these on an economic basis. The advantage of this optimization approach lies in its ability to quantify costs involved in tradeoffs among various technology choices, early plant retirement, and conversion. However, the approach does not lend itself to simulation of the rescheduling realities faced by the industry due to uncertain demand forecasts. In problems as large and complex as this one (which deals with individual plants), perfect certainty must be assumed in order for the optimization approach to be viable.

The current state-level AUSM leaves it to the user to specify these inputs. However, a capacity planning option that employs an aggregated optimization model has been developed at the regional level to simulate and quantify such tradeoffs as scrubber retrofit versus early plant retirement, coal conversion, and out-of-state siting to meet regional emission limits. This model, which is the national model, is discussed in the national model documentation. The AUSM planning module has been designed to accept as inputs the results of such optimization analyses, instead of relying solely on user-specified inputs.

The remainder of this analytical documentation volume consists of discussions of the analytical capabilities of each modular component of the AUSM: electricity demand (Chapter 2), finance (Chapter 3), coal supply (Chapter 4), pollution control (Chapter 5), dispatching (Chapter 6), and capacity planning (Chapter 7). Each discussion is written by the URGE researcher who developed the module in question. Descriptions of the AUSM electric generating unit inventory and the coal reserves data base appear in

Appendices A and B. The AUSM methodology for coal cleaning is described in Appendix C, while separate reports in this AUSM documentation series describe the energy and employment impacts module and the national model [19,20].

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2. THE DEMAND MODULE

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2.1 Introduction

The Advanced Utility Simulation Model (AUSM) has been designed using a state as the basic spacial unit and a year as the temporal unit. The model operates in an annually recursive way: that is, all modules are run in sequence for each state and each year. The underlying reason for doing this is to provide a more realistic representation of how electric utilities operate by making major feedback mechanisms explicit in the model. For example, projected future levels of the demand for electricity could be treated as predetermined values that never change for a given state. In reality, projections of demand are modified over time in response to changes in economic conditions. The causes of these new conditions -- such as changing expectations about economic growth -- may be external to the utility industry. More important changes may be determined within the industry. Examples of the latter include the consequences of adopting various policies for meeting different emission standards, as well as changing the methods by which costs are passed on to customers.

An annually recursive model could be prohibitively expensive to operate. To avoid this problem, each module of the AUSM had to be designed to be compact and efficient to operate. Thus, it was not practicable to design a module that required a large amount of input information for each state or year unless this information was essential to the overall analysis. The inventory of electric generating facilities, for example, can be considered as an essential component of the model. In the case of the demand module, a compromise had to be made between the level of detail of the output from the module and its operational characteristics. The requirement for designing an operationally efficient module was a major reason for choosing an econometric rather than an engineering end-use approach to the module. In other words, a compromise had to be made between the level of detail of the output from the module and its operational characteristics. The econometric structure was also valuable because it allows the demand equations to be recalibrated to meet user-selected projections of demand and still maintain price responsiveness.

The demand module is designed to operate in the following three ways:

1. *Endogenous demand.* The level of demand is determined in the model as a function of the price of electricity and of the exogenously specified inputs relating to economic conditions and the prices of primary fuels.

2. *Exogenous demand.* A user can specify any projection of total sales to ultimate customers as input data. The endogenously determined levels of demand in different sectors are recalibrated to correspond to the specified level of exogenous demand.

3. *Exogenous demand with annual recursiveness.* When a demand projection is defined exogenously in a base scenario, subsequent scenarios can be run that are compatible with this base and that also reflect how demand levels will change if the cost of generation is different from the base.

The first method of operation of the demand module makes it possible to derive independent forecasts of demand levels under different economic conditions. The second method of operation can be used to calibrate the model to another forecast (such as those from the U.S. Department of Energy or the National Electric Reliability Councils). In other words, this will make it possible to compare results from the AUSM with the results from other analyses using the same levels of demand. One or the other of the first two methods of operation is used in most utility models. The third method represents a way to combine desirable characteristics of the first two methods. For example, the effects of prices are ignored with exogenous demand, even if the costs of generation vary in different scenarios. In other words, it is assumed that higher prices have no effect on sales. Even though price effects are considered with endogenous demand, the predicted levels of sales may differ from the levels used in other studies, making comparisons difficult. With the third method of operation, it is possible to determine how costs affect demand as well as to calibrate demand to specified levels in a base scenario.

The demand module is the first module solved in the sequence of a scenario run. As such, it determines some of the initial conditions used in other modules for any given state and year. This is true regardless of which of the three modes of operation is used. If the complete model is operating for a state over time, operation of the demand module signifies when one year changes to the next. The information determined within the demand module can be summarized as follows:

1. The levels of energy and peak load demanded in the current year, net of interstate transfers, are determined for the dispatching module.

2. Total revenue and the net cost of interstate transfers are determined for the financial module.

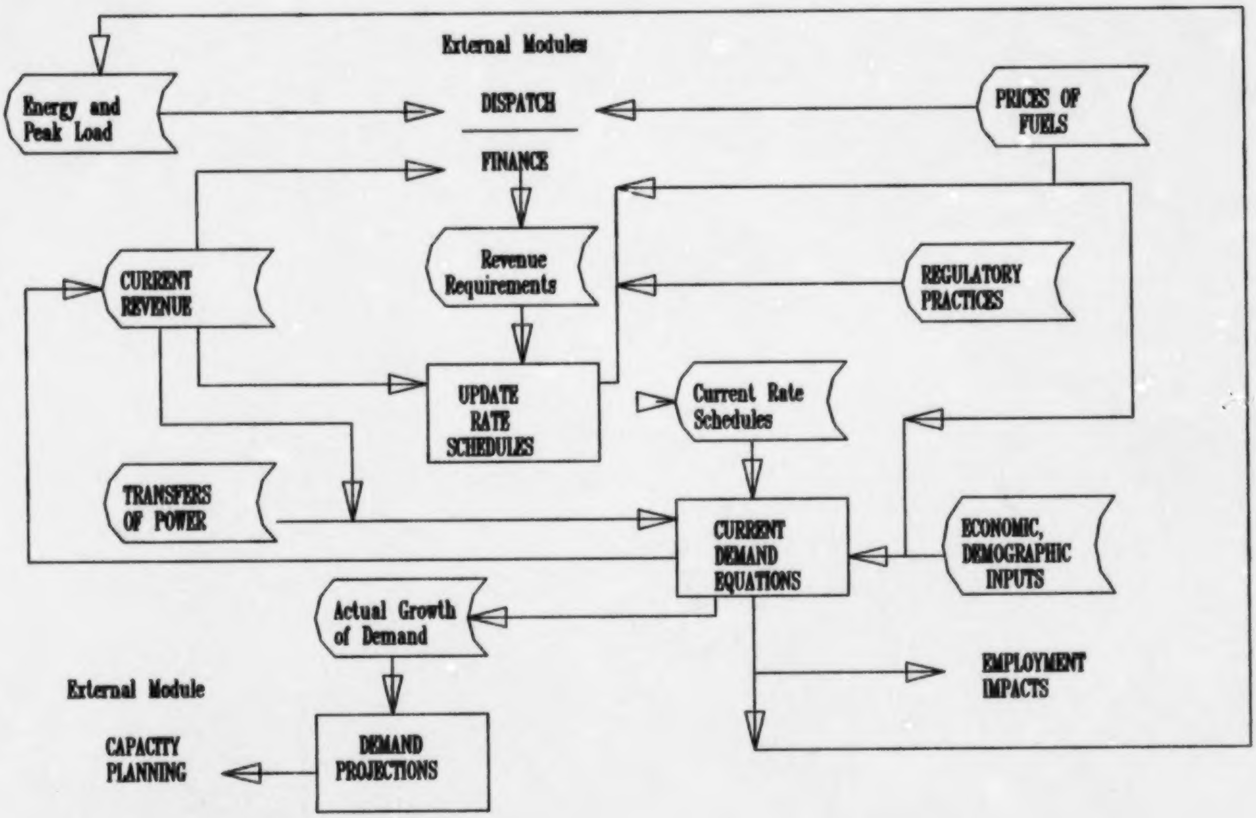
3. Projected levels of future demand are determined for the capacity planning module.

4. Information about the levels of demand for electricity and other fuels are determined and saved for subsequent use in the energy and employment impacts module.

The major components of the demand module are illustrated in Figure 2-1. This diagram identifies the input information needed for endogenous demand, as well as the four categories of output information described above. The input information can be conveniently classified either as specified externally or determined within the complete model. The most important input information determined within the model relates to revenue requirements; it includes the allowed return on capital as well as a breakdown of operating costs. This financial information is used to determine the rates charged to different sectors in the following year. The other main category of internal information, which is determined by the demand module itself, is saved for use in later years. This type of information is typically associated with the dynamic structure of the relationships in the module.

A large part of the external information used in the demand module relates to inputs for the demand equations. There are two major components: the first gives the prices of primary fuels; the second, economic and demographic information. Efforts have been made to reduce the amount of information needed with both types of inputs. For example, values of an input are provided for a few specified years, while intermediate values are computed by interpolation. The sectoral prices for a fuel in a given year are determined within the demand module from a single series that is specified externally. Furthermore, much of this input information is shared with other modules. The dispatching module, for example, uses the same prices of fuels as the demand module, and much of the economic information is used by the energy and employment impacts module. At present, information on interstate transfers of power is provided externally, but much of this information will be determined within the overall model if states are

Figure 2.1
SCHEMATIC REPRESENTATION OF THE DEMAND MODULE


External Modules
Energy and Peak Load
DISPATCH
PRICES OF FUELS
FINANCE
Revenue Requirements
CURRENT REVENUE
REGULATORY PRACTICES
UPDATE RATE SCHEDULES
Current Rate Schedules
TRANSFERS OF POWER
CURRENT DEMAND EQUATIONS
ECONOMIC, DEMOGRAPHIC INPUTS
Actual Growth of Demand
EMPLOYMENT IMPACTS
External Module
CAPACITY PLANNING
DEMAND PROJECTIONS

grouped into dispatching regions, as proposed. Finally, information on regulatory practices, which reflects the choice of procedure used to set rates, corresponds to a selection made when specifying a scenario. The underlying objective for specifying the input information needed for the demand module is parsimony, and efforts are continuing to simplify the input requirements even further.

Since the demand module is based on an econometric approach, most of the structural relationships within it are estimated from a sample of observations using statistical procedures. A large part of the effort for the project went into establishing a suitable data base for estimation. After a presentation of the module's structure in Section 2.2, some of the major principles that were adopted for selecting sources of data are discussed in Section 2.3.

2.2 Analytical Structure

The sources of data selected (see Section 2.3) make it feasible to consider disaggregating demand into five general sectors: residential, commercial, industrial, transportation, and electric utilities. Almost all of the final sales of electricity go to the first three sectors. Transportation is an important sector for oil use, but currently electricity use by this sector is essentially zero in most states, and very small in the rest. The use of electricity by electric utilities accounts for all of the differences between the quantity of electricity generated and final sales. Consequently, the most important "uses" in this sector relate to distribution losses and to interstate transfers of power. At the present time, demand questions have been developed for the residential, commercial, and industrial sectors. The demand for electricity by the transportation sector, if any, is treated as a proportion of the quantity demanded by the commercial sector.

Given the way in which the demand module is disaggregated into different sectors, the main features of the module can be summarized in terms of its four major components:

1. *Update Rate Schedules.* The information from the financial model is used to set new rates for electricity in the different sectors.

2. *Demand Equations.* These rates, together with externally provided information about the prices of primary fuels and economic conditions, are combined to predict the quantities of electricity and of primary fuels demanded in the different sectors for a given state in a particular year. When the module is

operated using exogenous demand, or exogenous demand with annual recursiveness, these predictions are recalibrated to be consistent with the exogenously supplied levels.

3. *Load Characteristics.* The sales of electricity to each sector are aggregated and modified to account for distribution and other losses and for interstate transfers. Additional load characteristics, such as the system load factor, are specified so that the information passed to the dispatching module reflects generation and peak load net of transfers.

4. *Demand Projections.* A projection is made of the system load 15 years ahead of the current year. This information is used in the planning module to develop a construction plan for new generating facilities. It should be noted that this component of the demand module is designed to approximate the planning processes used by electric utilities. Thus, the projection of demand is not derived directly from the demand equations.

In the subsections that follow, each of these four components of the demand module is discussed in more detail.

2.2.1 Update Rate Schedules

The most important characteristic of this component of the demand module is the way in which rate schedules are specified for a given demand sector. Since the basic units of the model are a state and a year, some form of simplification must be used to represent an aggregate of many different schedules in a sector. It is convenient to represent each aggregate rate schedule as a two-part tariff, implying that a fixed "customer charge" is made together with a fixed marginal price for each kilowatt hour. For example, a typical monthly bill for a residential customer using 500 kilowatt hours would be $30 if the marginal price is 4 cents per kilowatt hour and the customer charge is $10 (500 * .04 + 10). The corresponding average price is 6 cents per kilowatt hour.[1] Hence, the two-part tariff addresses declining block rates, which are still widely used throughout the industry. It also provides the basis for considering other mechanisms for setting rates, such as incremental cost pricing, while maintaining revenue requirements.

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[1] It should be noted that the customer charge includes the cost of kilowatt hours priced above 4 cents per kilowatt hour. Thus, if the first 100 kilowatt hours cost 5 cents per kilowatt hour and the rest 4 cents per kilowatt hour, 100(.05 - .04) = $5 is included in the customer charge.

As a result, the use of two-part tariffs offers a great deal more flexibility for policy analysis than the use of a single average price for each sector.

In spite of the relative simplicity of using a two-part tariff, most sources of data at the state level report average prices only by sector. Consequently, it was necessary to obtain additional information from other sources to determine the corresponding customer charge and marginal price for each state, year, and sector. The basic source is *Typical Electric Bills*, issued by the U.S. Department of Energy [1]. The average monthly bills for a number of different levels of demand (three or four) are given for residential, commercial, and industrial customers and each year for every state. It is possible to regress the bill against the level of demand for each state, year, and sector, and this was done using both linear and quadratic functions of the level demanded. This provides a smooth approximation of the actual relationship, which would be piecewise linear for a given multipart tariff. It was found that the linear approximation gave very similar results to the quadratic approximation, and the linear model was used for simplicity. This procedure was applied to every state, year, and sector to give $48 * 17 * 3$ different estimated rate schedules.

Although the slope and intercept of the estimated linear rate schedules correspond to the marginal price and the customer charge of a two-part tariff, these values were not used directly. The data used to compile *Typical Electric Bills* are not strictly representative of each state as a whole; rather, these data are for urban customers. As a result, the implied average price from the estimated linear rate schedules may differ from the observed average price for any state, year, or sector. To compensate, the estimated linear rate schedules were used to determine the ratio of marginal to average price at the average monthly level of use per customer.[2] This ratio was then applied to the observed average price to give a marginal price and customer charge that are consistent with the observed average price. Although this adjustment procedure was used for each state, year, and sector, differences between the estimated slopes in the regression models and the final marginal prices were not great in the residential and commercial sectors. In the industrial sector, however, the estimated slopes were typically larger than the final marginal prices.

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[2] In practice, the number of customers in a sector may fluctuate from year to year, particularly in the industrial sector, due to changes in the classification scheme. These fluctuations are not matched by fluctuations in the quantity of electricity demanded. As a result, exponentially smoothed series were used to calculate the average use per customer to avoid introducing spurious changes that reflect only a reclassification of customers.

As a rule, the resulting time series of marginal prices are substantially lower than the corresponding average prices, particularly in the residential sector. However, the differences between the two price series have tended to decrease over time. During the 1970s, customer charges gradually approached zero in the commercial and industrial sectors in many states, implying that rate schedules became approximately flat. In the residential sector, the importance of the customer charge as a source of revenue declined in most states, but rates do not seem to be approaching a flat schedule because a positive customer charge appears to be persisting.

The general characteristics of the changing importance of customer charges as a source of revenue in each sector are summarized in Table 2-1. In 1970, over 20 percent of the revenue from the residential sector came from customer charges (including premiums above the marginal price for early blocks) in all 48 states. In fact, half of the states collected over 30 percent of the revenue in this way. In contrast, the

Table 2-1
PERCENT DISTRIBUTION OF SECTORAL REVENUE FROM CUSTOMER CHARGES, 1970 AND 1980

	Number of States					
Percent of Sectoral Revenue	Residential 1970	Residential 1980	Commercial 1970	Commercial 1980	Industrial 1970	Industrial 1980
40% - 49%	3	0	1	0	0	0
30% - 39%	21	1	1	0	1	0
20% - 29%	24	8	13	3	2	0
10% - 19%	0	30	27	9	12	2
0% < 10%	0	9	6	36	33	46

importance of the customer charge was much smaller in the commercial and industrial sectors: only 15 and 3 states, respectively, got more than 20 percent of the sectoral revenue from customer charges.

In 1980, the importance of customer charges was generally less in all three sectors than in 1970. In the commercial sector, the number of states getting less than 10 percent of the revenue from customer charges increased from 6 in 1970 to 36 in 1980; in the industrial sector, the corresponding number increased from 33 to 46. In the residential sector, however, most states still got over 10 percent of the revenue from customer charges in 1980.

At this stage, the major reason for developing estimates of the marginal prices and customer charges is to provide data for estimating the demand equations. These estimates will also provide a more flexible framework for subsequent policy analyses. The next step is to construct an explicit link between the financial and demand modules so that the estimates of actual revenue and the "required" revenue determined in the financial module can be used to set the customer charges and marginal prices in each sector for the following year. This is the specific requirement of the "updating rate schedules" component. Three separate steps in this process can be identified:

1. Determine the expected total revenue requirements for the next year.
2. Allocate total revenue requirements among sectors.
3. Specify the rate structure within each sector.

These three steps can be viewed as components of actual rate-making practices. If current practices were modified to follow economic efficiency criteria more closely, the order of the steps would be reversed because marginal prices would be set (perhaps for specific time periods) to cover incremental costs. Ensuring that revenues provide a fair return to investors would be treated as a subsequent issue that could be handled in a number of different ways. For example, customer charges or credits could be specified to equate actual revenues with requirements.

The choice of the particular method for updating rate schedules from one year to the next can be treated as a scenario specification. The method used in the current version of the model implies that existing rate-making practices continue. Unfortunately, there is almost no discussion in the literature of actual rate-making practices from a modeling perspective. Most of the economic literature focuses on determining optimal rates. Furthermore, there is no simple way to get historical information on annual revenue requirements for states. Consequently, it is not feasible to try to fit a purely descriptive statistical model to sample data. The current procedure for updating rates is similar to the one adopted by Baughman, Joskow, and Kamat [2].

In the first stage, the difference between actual revenue and revenue requirements is passed on to investors; it represents a departure from a fair rate of return to investors. This difference is adjusted through regulatory hearings, and it is assumed, as do Baughman et al. [2, page 218], that only a specific proportion of the difference is awarded in rate adjustments accounting for the delay associated with regulatory hearings. This adjustment factor cannot be estimated directly because suitable sample data on revenue requirements are not available; it is treated as a state-specific input parameter. Higher fuel costs are assumed to be passed on through automatic fuel adjustment clauses. This is done by recomputing the average fuel cost in the previous year using projected fuel prices for the following year. Once again, a state-specific input parameter is defined for the process.

With regard to the way in which the overall price increment is passed on to different sectors, it is assumed that the same increment for fuel costs is passed on to all sectors. The nonfuel increment, representing adjustments to maintain a fair return to investors, is passed on in proportion to the nonfuel component of the price in each sector. This scheme can be illustrated as follows. If the average price in year t, $\overline{PEL_t}$, is divided into the average fuel cost, $\overline{FC_t}$, and nonfuel cost $\overline{NF_t}$, then

$$\overline{PEL_t} = \overline{FC_t} + \overline{NF_t} \ . \tag{1}$$

The increment to the average price associated with changing fuel prices can be written

$$\Delta\overline{FC_{t+1}} = \overline{FC_t}(PIF_{t+1}/PIF_t - 1) \ , \tag{2}$$

where PIF_t is the price index for fuels. In practice, the ratio of this price index for t+1 and t is determined by recomputing total fuel costs using the quantities of fuels used for generation in year t and the prices for year t+1, and dividing this by the actual fuel cost in year t. This implies that the price index reflects the actual pattern of fuel use in each state during the previous year.

The increment to the total price associated with the nonfuel component can be written

$$\Delta RR_{t+1} = \theta_1\,(\mathit{Required\ revenue}_t - \mathit{Actual\ revenue}_t)/QEL_t\,, \tag{3}$$

where QEL is total sales of electricity and $0 < \theta_1 \leq 1$ is the nonfuel adjustment factor. It is assumed that this increment is passed on as a proportional change in all nonfuel costs.[3] This proportion is the same in all sectors.

If $MPEL_{i,t}$ is the marginal price charged in sector i at time t, the updated prices can be written

$$MPEL_{i,t+1} = MPEL_{i,t} + \theta_2 * \Delta\overline{FC}_{t+1} + (MPEL_{i,t} - \overline{FC}_t) * \Delta\overline{RR}_{t+1}/\overline{NF}_t \tag{4}$$

where $0 < \theta_2 < 1$ is the fuel adjustment factor.

If $CC_{i,t}$ is the customer charge (including premiums above the marginal price in early blocks) in sector i at time t, then the updated customer charge can be written

$$CC_{i,t+1} = CC_{i,t}(1 + \Delta\overline{RR}_{t+1}/\overline{NF}_t). \tag{5}$$

This mechanism for setting rates is viewed as a logical starting point for approximating current regulatory practices. Efforts are now being made to evaluate how well the mechanism performs in the sample period and to compare its performance with alternative mechanisms based on regression models for allocating revenue responsibility to different sectors.

2.2.2 Demand Equations

2.2.2.1 The Structure of the Statistical Model. The basic structure of the demand equations is determined by the choice of sectors and of the products demanded. The demand sectors were identified above as residential, commercial, industrial, and transportation, and their selection was essentially dictated by the availability of data. The choice of products is also identified by the availability of data. In addition, this choice is designed to be consistent with the structure of other components of the model.

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[3] In a few states, the average price paid in the industrial sector may be relatively low if, for example, it receives a large share of cheap hydroelectro power. It is assumed that there is a minimum contribution to nonfuel costs in each sector, and if this minimum is binding, then fuel costs in the other sectors are adjusted up in proportion to sales so that total fuel costs are covered.

The underlying objective of the demand equations is to predict the quantities of electricity and of major primary fuels demanded in each sector. The following demand categories are identified in the model:

1. *Residential*

   Electricity
   Natural gas
   Oil (light)
   Oil (motor)

2. *Commercial*

   Electricity
   Natural gas
   Oil (light)
   Oil (heavy)

3. *Industrial*

   Electricity
   Natural gas
   Oil (light)
   Oil (heavy)
   Coal

4. *Transportation*

   Electricity
   Oil (light)
   Oil (heavy)
   Oil (motor)
   Oil (aviation)

The definitions of the different oil products require some further explanation. Each category represents an aggregate, but each aggregate is dominated by a single component. "Light" corresponds to distillate, "heavy" to residual; "motor" to gasoline, and "aviation" to jet fuel. In other words, the different categories of oil cover all types of oil products identified in the Federal Energy Data System developed by the U.S. Department of Energy. A more detailed description of the definitions will be given in a forthcoming report on data documentation [3].

Many different attempts have been made to model the demand for energy. The methods used are diverse, and there is no concensus about the best approach. A survey of research in this area has recently been completed by Douglas Bohi [4], who identifies many outstanding problems. The literature relating to electricity demand does reach some general agreement on at least two issues. The first is that prices do matter, implying that the demand for electricity does respond to changing prices. The second is that demand responses to price changes are dynamic, implying that adjustments occur gradually over time. The reason for the delay is that changes in the stock of electric appliances and equipment occur slowly. Even when prices increase, inefficient equipment is not replaced immediately.

The general implication of a dynamic demand system is that the immediate (short-run) response to price is small relative to the eventual (long-run) response. These dynamic characteristics can be assumed to apply to the demand for primary fuels as well as for electricity. Since one would expect the real cost of energy to increase substantially over the forecast period, which extends to the year 2000, an important issue is whether the expenditure patterns implied by a dynamic model are consistent with economic principles. Many single equation models, for example, are based on a constant elasticity form (linear in logarithms). If prices rise sufficiently and demand is inelastic, predicted expenditures on energy may exhaust all income. The form of demand equation used in the following analysis is designed to avoid this type of problem. The use of a dynamic model that is consistent with economic principles distinguishes the model from those presented in the majority of other studies. Most dynamic models ignore some important economic inconsistencies implied by the predicted responses, and most demand systems derived in accordance with economic theory are static. Although there are some exceptions (such as the work of Berndt et al. [5]), applying these methods is not feasible at the state level because data sources on stocks of capital equipment are inadequate. While the AUSM demand module offers no panacea, it does provide a relatively robust framework for deriving forecasts of energy demand, and it captures the main features of price responsiveness that have been identified in earlier studies.

The form of demand equation used is derived from a linear logit function. The standard representation of the demand problem facing consumers is to allocate a given amount of money to different products. In other words, how are total expenditures shared among products? A similar argument can be made for the allocation of total costs among the inputs used in a production process. The linear logit model can be used to predict the individual shares in this type of allocation problem. The predicted shares are always non-negative and add to one. This is an attractive property, one not necessarily exhibited by other models such as the constant-elasticity models discussed above. In other words, the elasticities derived from a linear logit model adjust as shares adjust in such a way that predicted levels of demand are consistent with economic logic. Consequently, the corresponding expressions for the response elasticities are somewhat different from the standard expressions in a constant-elasticity model.

A simple dynamic form of a constant-elasticity model can be written as follows:

$$\log Q_t = a + b\log Y_t + c\log P_t + d\log Q_{t-1} \tag{6}$$

where Q_t is the quantity demanded at time t. This quantity is a function of income, Y_t, the price, P_t, and the quantity demanded in the previous period. The terms a, b, c, and d are parameters that define the model. By substituting sequentially for the lagged quantities demanded while price and income are held constant, and noting that $(1 + d + d^2 + \ldots) = 1/(1 - d)$ if $0 < d < 1$, the demand equation can be rewritten as

$$\log Q_t = a/(1 - d) + b/(1 - d)\log Y + c/(1 - d)\log P \,. \tag{7}$$

The first form of the demand equation is the short-run response in which the lagged quantity is considered as given. The short-run elasticities are defined as

$$\partial \log Q/\partial \log Y = b \quad \text{for } income \tag{8}$$

and

$$\partial \log Q/\partial \log P = c \quad \text{for } price. \tag{9}$$

A conventional commodity would have $b > 0$ and $c < 0$. The second form of the equation represents the long-run response, and the long-run elasticities are defined as

$$\partial \log Q/\partial \log Y = b/(1 - d) \quad \text{for } income \tag{10}$$

and

$$\partial \log Q/\partial \log P = c/(1 - d) \quad \text{for } price. \tag{11}$$

In other words, both elasticities are absolutely greater in the long run than in the short run when $0 < d < 1$. The value of $(1 - d)$ is the proportion of the adjustment process that is completed in the first period.

The basic problem with this type of constant-elasticity model for a system of demand equations is that all the income elasticities cannot increase in the long run, because the implied elasticities will no longer be consistent with economic logic. If the elasticities are "well behaved" in the short run, implied expenditures will exceed income in the long run, and consequently will not conform to economic logic. It is reasonable, however, to expect all price responses to be larger in the long run.

With a linear logit model, each expenditure share can be written as follows:

$$w_i = exp(f_i)/\Sigma_j\ exp(f_j) \qquad i = 1,2, \ldots, N \tag{12}$$

where $w_i = P_i * Q_i$/total expenditures is the share of expenditures spent on commodity i and f_i is a linear function of the explanatory variables, such as prices and income. The form of this expression ensures that predicted shares are non-negative and sum to one. In addition, it is possible to linearize the model using any ratio of shares to give the following simple form for estimation:

$$log(w_i/w_N) = f_i - f_N\ . \tag{13}$$

The specified form of f_i is dynamic and includes the prices of all products (and income in the residential sector). A typical equation can be written:

$$\begin{aligned} log(w_i/w_N) = (a_i - a_N) + (b_i - b_N)logY + (c_{i1} - c_{N1})logP_1 + \cdots \\ + (c_{iN} - c_{NN})logP_N + dlog(Q_i/Q_N)_{-1} \end{aligned} \tag{14}$$

where, as before, Y as income, P_i and Q_i are the price and quantity of commodity i, and the subscript on the quantity ratio implies lagging one period. In the nonresidential sectors, the form of the equation is similar except that no income variable is included.[4]

The elasticities are derived from the linear logit model for a specified set of shares, $w_1^*, w_2^*, \ldots, w_N^*$.[5] For the residential sector (short run), these elasticities are

$$\partial \log Q_i/\partial \log Y = b_i - \Sigma_j w_j^* b_j + 1 \text{ for } \mathit{income}, \tag{15}$$

$$\partial \log Q_i/\partial \log P_i = c_{ii} - \Sigma_j w_j^* c_{ji} - 1 \text{ for } \mathit{own\text{-}price}, \tag{16}$$

and

---

[4] This implies that the shares are unaffected by the level of production and that production is linear homogenous in inputs.

[5] This discussion of the model is a summary of material presented in Reference 6.

$$\partial \log Q_i / \partial \log P_k = c_{ik} - \Sigma_j w_j^* c_{jk} \quad \text{for } \textit{cross-price } (i \neq k). \tag{17}$$

For nonresidential sectors (short run), they are

$$\partial \log Q_i / \partial \log P_i = c_{ii} - \Sigma_j w_j^* c_{ji} - 1 + w_i \quad \text{for } \textit{own-price} \tag{18}$$

and

$$\partial \log Q_i / \partial \log P_k = c_{ik} - \Sigma_j w_j^* c_{jk} + w_k \quad \text{for } \textit{cross-price } (i \neq k). \tag{19}$$

The basic form of each elasticity expression includes a weighted sum of the parameters; the weights correspond to the specified set of expenditure shares. The elasticity value changes when a different set of shares in the weighted sum are used, and this property is the one responsible for maintaining the economic logic of the model as economic conditions and hence predicted shares change. The difference between the expressions in the residential and nonresidential sectors results from the conventional definitions of price elasticities. In the residential model, price elasticities are defined with total expenditures (income) held constant, but in the nonresidential sectors, physical production is held constant, implying that total expenditures can change.

If the short-run and long-run price elasticities are defined as E_{ij}^{SR} and E_{ij}^{LR}, respectively, then in the nonresidential sectors, the long-run elasticities can be computed in a similar way to the constant-elasticity model.[6] These long-run, nonresidential elasticities are

$$E_{ij}^{LR} = E_{ij}^{SR}/(1 - d) \qquad \text{for } \textit{all } i \text{ and } j\ . \tag{20}$$

This implies that the long-run price elasticities are all greater than the short-run elasticities in absolute terms.

The expressions for the long-run elasticities in the residential sector are

$$E_{ij}^{LR} = (E_{ij}^{SR} + dw_j^*)/(1 - d) \qquad \text{for } \textit{all } i \text{ and } j \tag{21}$$

and

$$E_{ii}^{LR} = (E_{ii}^{SR} - d)/(1 - d) \tag{22}$$

---

[6] Note that this characteristic holds because the lagged term is defined as a quantity rather than an expenditure ratio.

where E_{iy}^{SR} and E_{iy}^{SR} are the short-run and long-run income elasticities, respectively. The additional term in each of these expressions for the long-run elasticities ensures that the economic logic of the model is maintained in both the short run and the long run. There are, however, some interesting differences that can be identified when comparing these results with the standard results for a constant-elasticity model.

In the short run, price responses will be relatively small. In the long run, substitution effects ($E_{ij}^{SR} > 0$) will be larger than the constant-elasticity results, but complementary effects and own-price effects ($E_{ij}^{SR} < 0$) will be smaller. It should be noted that the direct price effects will typically still be larger, in absolute terms, in the long run than in the short run. However, the constant-elasticity model tends to overestimate this difference, particularly if shares are large. The long-run income effects cannot all be larger than the short-run effects. A linear logit model recognizes this fact. In the long run, income elasticities tend to diverge more from unity than in the short run. In other words, if a commodity is income elastic (or inelastic) in the short run, it is more elastic (or inelastic) in the long run. This can be stated as

If

$$E_{iy}^{SR} < 1,\ E_{iy}^{LR} < E_{iy}^{SR}\ . \tag{23}$$

If

$$E_{iy}^{SR} > 1,\ E_{iy}^{LR} > E_{iy}^{SR}\ . \tag{24}$$

In other words, long-run income effects may be larger or smaller than the short-run effects, and this is perfectly consistent with economic logic. In the long run, people are able to make a greater distinction between necessities ($E_{iy} < 1$) and luxuries ($E_{iy} > 1$).

Other characteristics of the elasticities can be derived from economic theory. These are incorporated into the linear logit model through the use of linear constraints on the parameters. The first characteristic is that changing all prices (and income in the residential sector) by the same proportion leaves the predicted shares unchanged. The second is a symmetry condition implying that cross-equation constraints on the parameters should be imposed. These conditions have been incorporated into the estimated models, and it can be shown that these conditions are met if[7]

$$\Sigma_j c_{ij} = 0 \quad \text{for } all \ i \tag{25}$$

and

$$w_i^* c_{ij} = w_j^* c_{ji} \quad \text{for } all \ i \neq j \ . \tag{26}$$

In order to deal with complete systems of demand equations, it is necessary to consider expenditures on nonfuel items. In the residential sector, these other expenditures are treated as a single group. In the production sectors, typically, labor, capital, and possibly other nonfuel resources would be included. In this analysis, only labor is considered. The reason is the lack of suitable state-level data for the other inputs. While data on capital expenditures, for example, can be inputed from various sources for some states, this is not the case for all states. The lack of adequate series for capital expenditures by sector is a continuing problem for regional analyses.

2.2.2.2 **The Estimated Models**. At the present time, demand models have been estimated for the residential, commercial, and industrial sectors. The initial form of these three models is shown in Tables 2-2, 2-3, and 2-4. The relative complexity of the expressions results from incorporating the economic constraints of homogeneity and symmetry into the equations, because the symmetry constraints are defined for a specified set of expenditure shares (the average values in the sample for each sector). The price coefficients in these three tables correspond to (c_{ij}/w_j^*) so that the symmetry constaints can be applied directly. They have names of the form sC_{ij}, where s = R, C, and I for the three sectors.

Another feature of the models is that certain additional variables have been included to account for noneconomic factors. In particular, an effort was made to remove the unusual effects of the oil embargo in 1974, constraints on the supplies of natural gas in 1973-76, and the more relaxed standards that existed for air quality prior to the Clean Air Act in 1968-70. In the equations for electricity and natural gas, the number of customers per capita is included to account for the effects of changing the classification scheme for customers. Finally, price indices for appliances and automobiles are included in the residential sector. The underlying purpose for including all these variables is to try to improve the estimates of the price effects by removing possible sources of bias. These additional variables have coefficients with names of

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[7] In the residential sector, the appropriate income coefficient (b_i) is included in the first sum.

Table 2-2
INITIAL FORM OF RESIDENTIAL SECTOR DEMAND MODEL

```
Residential Sector:  Initial
****************************

PERDICTS EXPEDITURE SHARES FOR:
  1.  EL: ELECTRICITY
  2.  NG: NATURAL GAS
  3.  OL: OIL(LIGHT)
  4.  OM: OIL(MOTOR)
  5.  NF: OTHER NON-FUEL

ENDOGENOUS:
  LR_V          LOG OF EXPENDITURE RATIO
EXOGENOUS:
  D_            DUMMY VARIABLE FOR YEAR
  LC_P          LOG OF CUSTOMERS PER CAPITA BY FUEL
  LPAPP         LOG OF INDEX OF APPLIANCE PRICES
  LPCAR         LOG OF INDEX OF NEW CAR PRICES
  LP_Y          LOG OF PRICE/INCOME RATIO
  LQ_L          LOG OF LAGGED QUANTITIY RATIO
  LR_M          LOG OF MEAN EXPEDITURE RATIO BY STATE

PARAMETER:
  RW_           AVERAGE EXPENDITURE SHARE

SYMBOL DECLARATIONS

ENDOGENOUS:
  LR15V  LR25V  LR35V  LR45V

EXOGENOUS:
  D73  D74  D75  D76  LCELP  LCNGP  LPAPP  LPCAR  LP1Y  LP2Y  LP3Y  LP4Y  LP5Y
  LQ15L  LQ25L  LQ35L  LQ45L  LR15M  LR25M  LR35M  LR45M

COEFFICIENT:
  RC11  RC12  RC13  RC14  RC15  RC22  RC23  RC24  RC25  RC33  RC34  RC35  RC44  RC45
  RD11  RD13  RD174  RD24  RD273  RD274  RD275  RD276  RD374  RD43  RD474  RL

PARAMETER:
  RW1  RW2  RW3  RW4  RW5


EQUATIONS

            ELECTRICITY/OTHER NON-FUEL:
  1:        LR15V  = LR15M+(RC11-RC15)*RW1*LP1Y+(RC12-RC25)*RW2*LP2Y+(RC13-RC35)*RW3*LP3Y
            +(RC14-RC45)*RW4*LP4Y+RC15*RW5*LP5Y+RD11*LPAPP+RD13*LCELP+RD174*D74+RL*LQ15L

            NATURAL GAS/OTHER NON-FUEL:
  2:        LR25V  = LR25M+(RC12-RC15)*RW1*LP1Y+(RC22-RC25)*RW2*LP2Y+(RC23-RC35)*RW3*LP3Y
            +(RC24-RC45)*RW4*LP4Y+RC25*RW5*LP5Y+RD24*LCNGP+RD273*D73+RD274*D74+RD275*D75
            +RD276*D76+RL*LQ25L

            OIL(LIGHT)/OTHER NON-FUEL:
  3:        LR35V  = LR35M+(RC13-RC15)*RW1*LP1Y+(RC23-RC25)*RW2*LP2Y+(RC33-RC35)*RW3*LP3Y
            +(RC34-RC45)*RW4*LP4Y+RC35*RW5*LP5Y+RD374*D74+RL*LQ35L

            OIL(MOTOR)/OTHER NON-FUEL:
  4:        LR45V  = LR45M+(RC14-RC15)*RW1*LP1Y+(RC24-RC25)*RW2*LP2Y+(RC34-RC35)*RW3*LP3Y
            +(RC44-RC45)*RW4*LP4Y+RC45*RW5*LP5Y+RD42*LPCAR+RD474*D74+RL*LQ45L
```

Table 2-3

INITIAL FORM OF COMMERCIAL SECTOR DEMAND MODEL

```
Commercial Sector:  Initial
**************************

PERDICTS EXPEDITURE SHARES FOR:
  1.  EL:  ELECTRICITY
  2.  NG:  NATURAL GAS
  3.  OL:  OIL(LIGHT)
  4.  OM:  OIL(HEAVY)
  5.  LB:  LABOR

ENDOGENOUS:
  LR_V            LOG OF EXPENDITURE RATIO
EXOGENOUS:
  D_              DUMMY VARIABLE FOR YEAR
  LC_P            LOG OF CUSTOMERS PER CAPITA BY FUEL
  LP_5            LOG OF PRICE/WAGE RATIO
  LQ_L            LOG OF LAGGED QUANTITY RATIO
  LR_M            LOG OF MEAN EXPEDITURE RATIO BY STATE

PARAMETER:
  OW_             AVERAGE EXPENDITURE SHARE

SYMBOL DECLARATIONS

ENDOGENOUS:
  LR15V  LR25V  LR35V  LR45V

EXOGENOUS:
  D73  D74  D75  D76  LCELP  LCNGP  LP15  LP25  LP35  LP45
  LQ15L  LQ25L  LQ35L  LQ45L  LR15M  LR25M  LR35M  LR45M

COEFFICIENT:
  CC12  CC13  CC14  CC15  CC23  CC24  CC25  CC34  CC35  CC45
  CD11  CD174  CD22  CD273  CD274  CD275  CD276  CD374  CL

PARAMETER:
  CW1  CW2  CW3  CW4  CW5

EQUATIONS

          ELECTRICITY/LABOR:
  1:      LR15V  = LR15M-(CW2*CC12+CW3*CC13+CW4*CC14+CW5*CC15+CW1*CC15)*LP15+(CC12
          -CC25)*CW2*LP25+(CC13-CC35)*CW3*LP35+(CC14-CC45)*CW4*LP45+CD11*LCELP+
          CD174*D74+CL*LQ15L

          NATURAL GAS/LABOR:
  2:      LR25V  = LR25M+(CC12-CC15)*CW1*LP15-(CW1*CC22+CW3*CC23+CW4*CC24+CW5*CC25+
          CW2*CC25)*LP25+(CC23-CC35)*CW3*LP35+(CC24-CC45)*CW4*LP45+CD22*LCNGP+CD273
          *D73+CD274*D74+CD275*D75+CD276*D76+CL*LQ25L

          OIL(LIGHT)/LABOR:
  3:      LR35V  = LR35M+(CC13-CC15)*CW1*LP15+(CC23-CC25)*CW2*LP25-(CW1*CC13-CW2*CC23
          +CW4*CC34+CW5*CC35+CW3*CC35)*LP35+(CC34-CC45)*CW4*LP45+CD374*D74+CL*LQ35L

          OIL(HEAVY)/LABOR:
  4:      LR45V  = LR45M+(CC14-CC15)*CW1*LP15+(CC24-CC25)*CW2*LP25+(CC34-CC35)*CW3*LP35
          -(CW1*CC14+CW2*CC24+CW3*CC34+CW5*CC35+CW4*CC45)*LP45+CD474*D74+CL*LQ45L
```

Table 2-4

INITIAL FORM OF INDUSTRIAL SECTOR DEMAND MODEL

```
Industrial Sector:  Initial
****************************

PERDICTS EXPEDITURE SHARES FOR:
  1.  EL:  ELECTRICITY
  2.  NG: NATURAL GAS
  3.  OL:  OIL(LIGHT)
  4.  OM: OIL(HEAVY)
  5.  CL:  COAL
  6.  LB:  LABOR

ENDOGENOUS:
  LR_V              LOG OF EXPENDITURE RATIO
EXOGENOUS:
  D_                DUMMY VARIABLE FOR YEAR
  LC_P              LOG OF CUSTOMERS PER CAPITA BY FUEL
  LP_6              LOG OF PRICE/WAGE RATIO
  LQ_L              LOG OF LAGGED QUANTITY RATIO
  LR_M              LOG OF MEAN EXPEDITURE RATIO BY STATE

PARAMETER:
  IW_               AVERAGE EXPENDITURE SHARE

SYMBOL DECLARATIONS

ENDOGENOUS:
  LR16V  LR26V  LR36V  LR46V  LR56V

EXOGENOUS:
  D68  D69  D70  D73  D74  D75  D76  LCELP  LCNGP  LP16  LP26  LP36  LP46  LP56
  LQ16L  LQ26L  LQ36L  LQ46L  LQ56L  LR16M  LR26M  LR36M  LR46M  LR56M

COEFFICIENT:
  IC12  IC13  IC14  IC15  IC16  IC23  IC24  IC25  IC26  IC34  IC35  IC36  IC45  IC46  IC56
  ID11  ID174  ID22  ID273  ID274  ID275  ID276  ID374  ID474  ID568  ID569  ID570  ID574  IL

PARAMETER:
  IW1  IW2  IW3  IW4  IW5  IW6


EQUATIONS

          ELECTRICITY/LABOR:
  1:      LR16V  = LR16M-(IW2*IC12+IW3*IC13+IW4*IC14+IW5*IC15+IW6*IC16+IW1*IC16)*LP16+(IC12
          -IC26)*IW2*LP26+(IC13-IC36)*IW3*LP36+(IC14-IC46)*IW4*LP46+(IC15-IC56)*IW5*LP56+ID11
          *LCELP+ID174*D74+IL*LQ16L

          NATURAL GAS/LABOR:
  2:      LR26V  = LR26M+(IC12-IC16)*IW1*LP16-(IW1*IC12+IW3*IC23+IW4*IC24+IW5*IC25+IW6*IC26+
          IW2*IC26)*LP26+(IC23-IC36)*IW3*LP36+(IC24-IC46)*IW4*LP46+(IC25-IC26)*IW5*LP56+ID22
          *LCNGP+ID273*D73+ID274*D74+ID275*D75+ID276*D76+IL*LQ26L

          OIL(LIGHT)/LABOR:
  3:      LR36V  = LR36M+(IC13-IC16)*IW1*LP16+(IC23-IC26)*IW2*LP26-(IW1*IC13+IW2*IC23+IW4*IC34
          +IW5*IC35+IW6*IC36+IW3*IC36)*LP36+(IC34-IC46)*IW4*LP46+(IC35-IC56)*IW5*LP56+ID374*D74
          +IL*LQ36L

          OIL(HEAVY)/LABOR:
  4:      LR46V  = LR46M+(IC14-IC16)*IW1*LP16+(IC24-IC26)*IW2*LP26+(IC34-IC36)*IW3*LP36-(IW1*
          IC14+IW2*IC24+IW3*IC34+IW5*IC45+IW6*IC46+IW4*IC46)*LP46+(IC45-IC56)*IW5*LP56
          +ID474*D74+IL*LQ46L

          COAL/LABOR:
  5:      LR56V  = LR56M+(IC15-IC16)*IW1*LP16+(IC25-IC26)*IW2*LP26+(IC35-IC36)*IW3*LP36+(IC45-IC46)
          *IW4*LP46-(IW1*IC15+IW2*IC25+IW3*IC35+IW4*IC45+IW6*IC56+IW5*IC56)*LP56+ID568*D68
          +ID569*D69+ID570*D70+ID574*D74+IL*LQ56L
```

the form _D__ in Tables 2-2, 2-3, and 2-4.

A system of linear equations with constraints on the parameters in different equations can be estimated using standard multivariate regression techniques. The parameters were estimated using an iterative, generalized least squares estimator for seemingly unrelated regressions. This method accounts for differences in the variances of the residuals in each equation and for covariances across equations. The reasons for doing this are to improve the accuracy of the estimation procedure and to ensure that the estimates are invariant to the choice of base input in the share ratios.

Although data were collected for all 48 states, the models were estimated from a subset of 12 states. The reason for this was two-fold. First, since each system of equations is estimated simultaneously, the implied sample size (number of equations x number of years x number of states) is large, and computational costs would be substantial. Second, the form of the equations is based on the logarithm of expenditure shares. If shares are very small, large proportional changes can be implied in the data that may distort the results. To avoid this problem, some states were eliminated for estimation purposes, typically because the use of natural gas or of coal was very small. Finally, a random sample of 12 states was selected.[8] Standard procedures were then following by estimating the models for the subset of states and then comparing the performance of the estimated models for the 12 states with the performance of the other 36 states. In all cases, the data are transformed to remove means for each state. State-specific intercepts are then computed for each equation.

In spite of the considerable effort to establish an accurate data base, pecularities in the data created serious problems for estimation. These problems made the estimated elasticities unrealistic, as illustrated in Table 2-5. In particular, if the equations for electricity were estimted separately, the results seemed reasonable. When the full system of equations was estimated, however, the results were very different, and were not consistent with economic logic. For example, some direct price effects were positive. The source of these changes was eventually linked to the data for the quantities of light and heavy oil. Discontinuities in these time-series observations were related to changes made in the methods used in the U.S. Department of Energy (DOE) to collect oil information. Although these discrepancies have been

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[8] The states are New York, Pennsylvania, Indiana, Michigan, Wisconsin, Minnesota, Iowa, Alabama, North Dakota, Nebraska, Wyoming, and Nevada.

Table 2-5
ECONOMIC CHARACTERISTICS OF THE INITIAL MODEL: ESTIMATED LONG-RUN ELASTICITIES

Residential	PEL	PNG	POL	POM	PNF	INC
QEL	-0.32	0.05	-0.00	0.19	0.40	-0.33
QNG	0.10	-0.03	-0.23	0.33	0.00	-0.17
QOL	0.01	-0.16	0.22	-2.35	3.50	-1.21
QOM	0.05	0.05	-0.52	0.38	0.14	-0.10
QNF	-0.01	-0.01	0.01	-0.05	-1.05	1.11

Commercial	PEL	PNG	POL	POH	PLB
QEL	-0.51	0.05	0.30	0.00	0.17
QNG	0.17	0.26	-0.16	-0.32	0.04
QOL	0.98	-0.14	-1.46	0.24	0.38
QOH	0.01	-0.28	0.23	-0.53	0.56
QLB	0.00	0.00	0.00	0.00	-0.01

Industrial	PEL	PNG	POL	POH	PCL	PLB
QEL	0.42	0.26	-0.33	0.13	-0.51	0.02
QNG	0.40	-1.48	0.15	0.21	0.10	0.61
QOL	-.044	0.13	2.24	-0.73	0.21	-1.41
QOH	0.16	0.17	-0.65	0.45	-0.11	-0.02
QCL	-2.70	0.36	0.81	-0.48	0.84	1.17
QLB	0.00	0.02	-0.05	-0.00	0.01	0.02

Q __ Quantity of __
P __ Price of __

EL	Electricity	CL	Coal
NG	Natural Gas	NF	Nonfuel
OL	Oil (light)	LB	Labor
OH	Oil (heavy)	INC	Income
OM	Oil (motor)		

recognized by the staff at DOE, they have not been able to correct them because of budgetary difficulties. Since one of the major contributions of the Federal Energy Data System was to provide information on the sectoral uses of oil at the state level that had not been available previously, it is particularly unfortunate that these series have not been corrected.

The solution adopted to overcome the poor quality of the oil data was to remove the symmetry constraints in the oil equations for estimation purposes. The oil equations were reconstructed after estimation to form a consistent system of equations. In other words, as much information from the non-oil equations as possible was used to develop the system of demand equations. This effort was aided by treating energy as a separable group, and light and heavy oil as a separable pair of inputs within the energy group in the commercial and industrial sectors.[9] The implication of these separability conditions is that the allocation of expenditures can be considered to take place in two steps. The first step involves allocations to major groups, such as energy, and the second involves allocations within each group. Consequently, this type of simplification is reasonable for broadly defined groups containing similar commodities or inputs such as energy.

The final models with the separability conditions included and the symmetry conditions for the oil equations removed are summarized in Tables 2-6, 2-7, and 2-8, for the residential, commercial, and industrial sectors, respectively. The estimated coefficients are included in each table. Estimates for both the ordinary least squares and the generalized least squares estimators are presented. Since the latter estimator involves an interative search, the former estimator is used to provide initial value for the search and thus reduce the computational requirements.

A summary of the fit of the individual equations is given in Table 2-9.[10] It is clear that the fit ($R^2 = 1$ corresponds to perfect fit) is good for the non-oil equations and reasonably good for the other equations. In addition, since the units for every equation are the same (logarithm of an expenditure ratio), the size of the unexplained error (SER) is smallest for the electricity equation in all three sectors.

In all three models, the coefficients with names of the form _B__ refer to coefficients added to the initial model to remove the symmetry constraints in the oil equations. In effect, these coefficients are estimated and then set to zero for forecasting purposes. In the commercial and industrial sectors, it is not

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[9] Highway fuels were not included in the energy group in the residential sector because the other fuels represent domestic rather than transportation uses.

[10] Additional summary statistics relating to the estimated models are available, but are not presented here. One noteworthy characteristic is that there is no indication of high collinearity among the regressors, based on the low condition numbers of the matrix of regressors in every sector.

Table 2-6

FINAL FORM OF RESIDENTIAL SECTOR DEMAND MODEL

```
Residential Sector:  Final
**************************

PERDICTS EXPEDITURE SHARES FOR:
  1. EL: ELECTRICITY
  2. NG: NATURAL GAS
  3. OL: OIL(LIGHT)
  4. OM: OIL(MOTOR)
  5. NF: OTHER NON-FUEL

ENDOGENOUS:
  LR_V          LOG OF EXPENDITURE RATIO
EXOGENOUS:
  D_            DUMMY VARIABLE FOR YEAR
  LC_P          LOG OF CUSTOMERS PER CAPITA BY FUEL
  LPAPP         LOG OF INDEX OF APPLIANCE PRICES
  LPCAR         LOG OF INDEX OF NEW CAR PRICES
  LP_Y          LOG OF PRICE/INCOME RATIO
  LQ_L          LOG OF LAGGED QUANTITY RATIO
  LR_M          LOG OF MEAN EXPEDITURE RATIO BY STATE

PARAMETER:
  RW_           AVERAGE EXPENDITURE SHARE


SYMBOL DECLARATIONS

ENDOGENOUS:
  LR15V  LR25V  LR35V  LR45V

EXOGENOUS:
  D73  D74  D75  D76  LCELP  LCNGP  LPAPP  LPCAR  LP1Y  LP2Y  LP3Y  LP4Y  LP5Y
  LQ15L  LQ25L  LQ35L  LQ45L  LR15M  LR25M  LR35M  LR45M

COEFFICIENT:
  RB3L  RB31 RB32 RB33 RB34  RB36  RCA4  RCA5  RC12  RC13  RC23  RC45  RC46
  RD11  RD13  RD174  RD24  RD273  RD274  RD275  RD276  RD374  RD42  RD474  RL

PARAMETER:
  RW1  RW2  RW3  RW4  RW5


EQUATIONS

        ELECTRICITY/OTHER NON-FUEL:
  1:    LR15V  = LR15M-(RC12*RW2+RC13*RW3+RCA4*RW4+RCA5*RW5+RCA5*RW1)*(LP1Y-LP5Y)+
        (RC12-RCA5)*RW2*(LP2Y-LP5Y)+(RC13-RCA5)*RW3*(LP3Y-LP5Y)+(RCA4-RCA5)*RW4*
        (LP4Y-LP5Y)-(RL-1)*LP1Y+RD11*LPAPP+RD13*LCELP+RD174*D74+RL*LQ15L

        NATURAL GAS/OTHER NON-FUEL:
  2:    LR25V  = LR25M+(RC12-RCA5)*RW1*(LP1Y-LP5Y)+(RC12*RW1+RC23*RW3+RCA4*RW4+
        RCA5*RW5+RCA5*RW2)*(LP2Y-LP5Y)+(RC23-RCA5)*RW3*(LP3Y-LP5Y)+(RC24-RC45)*RW4
        *(LP4Y-LP5Y)-(RL-1)*LP2Y+RD24*LCNGP+RD273*D73+RD274*D74+RD275*D75
        +RD276*D76+RL*LQ25L

        OIL(LIGHT)/OTHER NON-FUEL:
  3:    LR35V  = LR35M+(RB31+RC13-RCA5)*RW1*(LP1Y-LP5Y)+(RB32+RC23-RCA5)*RW2*(LP2Y-LP5Y)
        -(RB33+RC13*RW1+RC23*RW2+RCA4*RW4+RCA5*RW5+RCA5*RW3)*(LP3Y-LP5Y)+(RB34+RB4A-RC45)
        *RW4*(LP4Y-LP5Y)-(RB36+RL-1)*LP3Y+RD374*D74+(RB3L+RL)*LQ35L

        OIL(MOTOR)/OTHER NON-FUEL:
  4:    LR45V  = LR45M+(RCA4-RCA5)*RW1*(LP1Y-LP5Y)+(RCA4-RCA5)*RW2*(LP2Y-LP5Y)+
        (RCA4-RCA5)*RW3*(LP3Y-LP5Y)-(RCA4*RW1+RCA4*RW2+RCA4*RW3+RC45*RW5+RC45*RW4)
        *(LP4Y-LP5Y)-RC46*LP4Y+RD42*LPCAR+RD474*D74+RL*LQ45L
```

Table 2-6 (con't)

Coefficient	*Ordinary Least Squares*		*Generalized Least Squares*	
	Estimated Value	t Statistic	Estimated Value	t Statistic
RB31	-15.18	-1.66	-3.90	-0.41
RB32	-38.92	-2.43	-62.88	-2.87
RB33	0.04	0.22	-0.20	-0.89
RB34	-28.24	-5.87	-23.00	-3.31
RB36	-0.54	-3.44	-0.13	-0.58
RB3L	-0.17	1.81	0.22	2.22
RC12	3.09	0.71	3.20	1.67
RC13	12.60	1.63	9.35	2.87
RCA4	-1.37	-0.64	-0.54	-0.56
RCA5	-0.23	-1.90	-0.37	-6.43
RC23	2.99	0.35	2.33	0.61
RC45	-0.12	-0.63	-0.29	-3.21
RC46	-0.69	-4.80	-0.53	-7.96
RD11	-0.47	-1.64	-0.54	-5.37
RD13	0.98	2.24	0.65	4.10
RD174	-0.04	-1.10	-0.03	-2.50
RD24	0.48	2.93	0.38	5.25
RD273	-0.08	-2.70	-0.07	-5.78
RD274	-0.02	-0.49	-0.01	-0.65
RD245	-0.00	-0.10	-0.00	-0.13
RD276	-0.01	-0.29	-0.02	-1.38
RD374	0.07	2.15	0.05	0.87
RD42	-0.94	-4.34	-0.72	-7.02
RD474	-0.05	-1.75	-1.04	-2.52
RL	0.33	4.56	0.42	12.96

Table 2-7

FINAL FORM OF COMMERCIAL SECTOR DEMAND MODEL

```
Commercial Sector:  Final
************************

PERDICTS EXPEDITURE SHARES FOR:
  1.  EL:  ELECTRICITY
  2.  NG:  NATURAL GAS
  3.  OL:  OIL(LIGHT)
  4.  OM:  OIL(HEAVY)
  5.  LB:  LABOR

ENDOGENOUS:
  LR_V            LOG OF EXPENDITURE RATIO
EXOGENOUS:
  D_              DUMMY VARIABLE FOR YEAR
  LC_P            LOG OF CUSTOMERS PER CAPITA BY FUEL
  LP_5            LOG OF PRICE/WAGE RATIO
  LQ_L            LOG OF LAGGED QUANTITY RATIO
  LR_M            LOG OF MEAN EXPEDITURE RATIO BY STATE

PARAMETER:
  OW_             AVERAGE EXPENDITURE SHARE

SYMBOL DECLARATIONS

ENDOGENOUS:
  LR15V  LR25V  LR35V  LR45V

EXOGENOUS:
  D73  D74  D75  D76  LCELP  LCNGP  LP15  LP25  LP35  LP45
  LQ15L  LQ25L  LQ35L  LQ45L  LR15M  LR25M  LR35M  LR45M

COEFFICIENT:
  CB3L  CB31  CB32  CD33  CD4L  CB41  CB42  CB43  CB44  CCA5  CC12  CC13  CC23
  CC34A  CD11  CD174  CD22  CD273  CD274  CD275  CD276  CD374A  CD474A  CL

PARAMETER:
  CW1  CW2  CW3  CW4  CW5

EQUATIONS

          ELECTRICITY/LABOR:
  1:      LR15V  = LR15M-(CW2*CC12+CW3*CC13+CW4*CC14+CW5*CCA5+CW1*CCA5)*LP15+(CC12
          -CCA5)*CW2*LP25+(CC13-CCA5)*CW3*LP35+(CC13-CCA5)*CW4*LP45+CD11*LCELP+
          CD174*D74+CL*LQ15L

          NATURAL GAS/LABOR:
  2:      LR25V  = LR25M+(CC12-CCA5)*CW1*LP15-(CW1*CC22+CW3*CC23+CW4*CC23+CW5*CCA5+
          CW2*CCA5)*LP25+(CC23-CCA5)*CW3*LP35+(CC23-CCA5)*CW4*LP45+CD22*LCNGP+CD273
          *D73+CD274*D74+CD275*D75+CD276*D76+CL*LQ25L

          OIL(LIGHT)/LABOR:
  3:      LR35V  = LR35M+(CB31+CC13-CCA5)*CW1*LP15+(CB32+CC23-CCA5)*CW2*LP25-(CB32+CW1*CC13
          +CW2*CC23+CW4*CC34A+CW5*CCA5+CW3*CCA5)*LP35+(CC34A-CCA5)*CW4*LP45+CD374A*D74
          +(CB3L+CL)*LQ35L

          OIL(MOTOR)/LABOR:
  4:      LR45V  = LR45M+(CB41+CC13-CCA5)*CW1*LP15+(CB42+CC23-CCA5)*CW2*LP25+(CB43+CC34A-CCA5)
          *CW3*LP35-(CB44+CW1*CC13+CW2*CC23+CW3*CC34A+CW5*CCA5+CW4*CCA5)*LP45+CD474A*D74
          +(CB4L+CL)*LQ45L
```

Table 2-7 (con't)

Coefficient	*Ordinary Least Squares* Estimated Value	t Statistic	*Generalized Least Squares* Estimated Value	t Statistic
CB31	30.37	3.63	29.66	3.37
CB32	-19.48	-0.64	-4.06	-0.10
CB33	0.44	2.62	0.51	3.48
CB3L	-0.23	-2.06	-0.32	-3.34
CB41	6.96	0.83	8.03	1.12
CB42	60.10	1.97	68.01	2.01
CB43	-263.83	-7.41	-254.76	-4.85
CB44	-0.90	-4.76	-0.81	-3.84
CB4L	-.41	-3.59	-0.32	-3.97
CC12	1.15	0.22	0.17	0.09
CC13	-0.22	-0.04	-1.23	-0.70
CCA5	-0.89	-13.12	-0.89	-42.36
CC23	-6.47	-0.66	-8.19	-2.03
CC34A	92.05	5.18	88.69	3.41
CD11	0.17	0.49	0.17	1.80
CD174	-0.04	-0.86	-0.04	-2.97
CD22	0.22	1.69	0.21	3.89
CD273	-0.06	-1.22	-0.06	-3.10
CD274	-0.02	-0.25	-0.01	-0.31
CD275	0.06	0.99	0.06	2.55
CD276	-0.00	-0.09	-0.00	-0.06
CD374A	-0.01	-0.21	0.01	0.13
CD474A	0.11	1.91	0.11	1.71
CL	0.80	9.33	0.84	27.61
CC34			4.79	0.53
CD374			-0.08	-1.38
CD474			-0.04	-0.79

Table 2-8

FINAL FORM OF INDUSTRIAL SECTOR DEMAND MODEL

```
Industrial Sector:  Final
**************************

PERDICTS EXPEDITURE SHARES FOR:
  1.  EL:  ELECTRICITY
  2.  NG:  NATURAL GAS
  3.  OL:  OIL(LIGHT)
  4.  OM:  OIL(HEAVY)
  5.  CL:  COAL
  6.  LB:  LABOR

ENDOGENOUS:
  LR_V          LOG OF EXPENDITURE RATIO
EXOGENOUS:
  D_            DUMMY VARIABLE FOR YEAR
  LC_P          LOG OF CUSTOMERS PER CAPITA BY FUEL
  LP_6          LOG OF PRICE/WAGE RATIO
  LQ_L          LOG OF LAGGED QUANTITY RATIO
  LR_M          LOG OF MEAN EXPEDITURE RATIO BY STATE

PARAMETER:
  IW_           AVERAGE EXPENDITURE SHARE

SYMBOL DECLARATIONS

ENDOGENOUS:
  LR16V  LR26V  LR36V  LR46V  LR56V

EXOGENOUS:
  D68  D69  D70  D73  D74  D75  D76  LCELP  LCNGP  LP16  LP26  LP36  LP46  LP56
  LQ16L  LQ26L  LQ36L  LQ46L  LQ56L  LR16M  LR26M  LR36M  LR46M  LR56M

COEFFICIENT:
  IB3L  IB31  IB32  IB33  IB35  IB4L  IB41  IB42  IB43  IB44  IB45  ICA6
  IC12  IC13  IC15  IC23  IC25  IC34A  IC35  ID11  ID174  ID22  ID273  ID274
  ID275  ID276  ID374A  ID474A  ID568  ID569  ID570  ID574  IL

PARAMETER:
  IW1  IW2  IW3  IW4  IW5  IW6

EQUATIONS

        ELECTRICITY/LABOR:
 1:     LR16V  = LR16M-(IW2*IC12+IW3*IC13+IW4*IC13+IW5*IC15+IW6*ICA6+IW1*ICA6)*LP16+(IC12-
        ICA6)*IW2*LP26+(IC13-ICA6)*IW3*LP36+(IC13-IC46)*IW4*LP46+(IC15-IC56)*IW5*LP56+ID11
        *LCELP+ID174*D74+IL*LQ16L

        NATURAL GAS/LABOR:
 2:     LR26V  = LR26M+(IC12-ICA6)*IW1*LP16-(IW1*IC12+IW3*IC23+IW4*IC23+IW5*IC25+IW6*ICA6+
        IW2*ICA6)*LP26+(IC23-ICA6)*IW3*LP36+(IC23-IC46)*IW4*LP46+(IC25-ICA6)*IW5*LP56+ID22
        *LCNGP+ID273*D73+ID274*D74+ID275*D75+ID276*D76+IL*LQ26L

        OIL(LIGHT)/LABOR:
 3:     LR36V  = LR36M+(IB31+IC13-ICA6)*IW1*LP16+(IB32+IC23-ICA6)*IW2*LP26-(IB33+IW1*IC13+IW2*
        IC23+IW4*IC34A+IW5*IC35+IW6*ICA6+IW3*ICA6)*LP36+(IC34A-IC46)*IW4*LP46+(IB35+IC35-ICA6)
        *IW5*LP56+ID374A*D74+(IB3L+IL)*LQ36L

        OIL(HEAVY)/LABOR:
 4:     LR46V  = LR46M+(IB41+IC13-ICA6)*IW1*LP16+(IB42+IC23-ICA6)*IW2*LP26+(IB43+IC34A-ICA6)
        *IW3*LP36-(IB44+IW1*IC13+IW2*IC23+IW3*IC34A+IW5*IC35+IW6*IC46+IW4*IC46)*LP46+(IB45+IC45
        -IC56)*IW5*LP56+ID474A*D74+(IB4L+IL)*LQ46L

        COAL/LABOR:
 5:     LR56V  = LR56M+(IC15-ICA6)*IW1*LP16+(IC25-ICA6)*IW2*LP26+(IC35-ICA6)*IW3*LP36+(IC35-IC46)
        *IW4*LP46-(IW1*IC15+IW2*IC25+IW3*IC35+IW4*IC35+IW6*ICA6+IW5*ICA6)*LP56+ID568*D68
        +ID569*D69+ID570*D70+ID574*D74+IL*LQ56L
```

Table 2-8 (con't)

Coefficient	*Ordinary Least Squares*		*Generalized Least Squares*	
	Estimated Value	t Statistic	Estimated Value	t Statistic
IB31	-3.49	-0.93	-0.48	-0.11
IB32	-7.32	-1.80	-8.52	-1.88
IB33	-.70	-4.23	-0.68	-4.01
IB34	-1.59	-0.10	-8.66	-0.47
IB3L	0.16	1.90	0.11	1.31
IB41	5.82	1.55	8.87	2.64
IB42	-3.52	-0.87	-4.23	-1.12
IB43	-10.17	-2.03	-7.05	-1.31
IB44	-0.49	-2.79	-0.34	-1.87
IB45	-11.98	-0.77	-19.59	-1.37
IB4L	0.21	1.91	0.17	1.78
IC12	1.83	1.11	2.35	2.97
IC13	0.58	0.47	-0.50	-1.09
IC15	-3.69	-1.44	1.23	0.56
ICA6	-0.94	-20.67	-0.99	-42.91
IC23	3.44	1.57	3.53	2.14
IC25	-0.16	-0.05	0.54	0.16
IC34A	0.58	0.21	-0.59	-0.18
IC35	-0.01	-0.01	-0.13	-0.07
ID11	0.07	1.60	0.06	4.10
ID174	-0.07	-1.20	-0.04	-2.10
ID22	0.11	2.76	0.11	3.81
ID273	-0.04	-0.83	-0.03	-0.98
ID274	-0.19	-2.11	-0.20	-2.90
ID275	-0.15	-2.54	-0.16	-3.55
ID276	-0.13	-2.83	-0.15	-4.52
ID374A	-0.22	-3.44	-0.22	-2.89
ID474A	-0.07	-1.14	-0.07	-1.21
ID568	-0.02	-0.41	-0.04	-0.71
ID569	0.12	2.60	0.12	1.99
ID570	0.14	3.07	0.12	2.08
ID594	-0.13	-1.98	-0.10	-1.30
IL	0.69	17.37	0.71	24.36
IC34			1.11	.33
ID374			.00	.04
ID474			.09	.36

Table 2-9
SUMMARY OF THE FIT OF THE ESTIMATED EQUATIONS IN THE FINAL MODEL

Sector	Equation	R^2[a]	SER[b]
Residential	Electricity/Other	.985	.036
	Natural Gas/Other	.975	.045
	Oil (Light)/Other	.841	.170
	Oil (Motor)/Other	.978	.047
Commercial	Electricity/Labor	.981	.039
	Natural Gas/Labor	.976	.062
	Oil (Light)/Labor	.836	.216
	Oil (Heavy)/Labor	.927	.174
Industrial	Electricity/Labor	.994	.036
	Natural Gas/Labor	.968	.101
	Oil (Light)/Labor	.986	.154
	Oil (Heavy)/Labor	.985	.122
	Coal/Labor	.960	.165

[a] Pseudo-R^2 = (1 - unexplained variability/total variability).

[b] Estimated standard error of the equation.

possible to determine all of the price coefficients in the oil equations this way. The coefficient _C34 relates to the substitutability between light and heavy oil; this cannot be derived from the non-oil equations. The method chosen to estimate this coefficient was to fit the oil equations to the average time-series for all 48 states.[11] In this regression, the other coefficients are treated as known parameters, using the estimated price coefficients (_C__) from the complete system, and the added oil coefficients (_B__) are set to zero.[12]

The economic characteristics of the final models are much more realistic than they were for the initial models. The results are generally consistent with prior expectations. The estimated long-run elasticities are summarized in Table 2-10. Of particular importance to this analysis are the values of the own-price elasticities for electricity. The short-run effects are -0.18, -0.11, and -0.16 in the residential, commercial, and industrial sectors, respectively. The corresponding long-run elasticities are -0.30, -0.65, and -0.55. These elasticities are at the low end of the range of values estimated in other studies [4], and are smaller in absolute terms than earlier estimates that we have made using single-equation models [7]. It should be noted that the small long-run income elasticities for electricity and other fuels in the residential sector can be attributed to the way in which these elasticities are computed. As explained above, standard procedures for computing long-run income elasticities for a single-equation model are not consistent with the dynamics of a complete demand system. The estimated short-run income eleasticity is .46, which is consistent with other studies.

The effects of the prices of primary fuels on the demand for electricity indicate that natural gas and light oil are substitutes, with the latter being more important. In the commercial sector, natural gas is a weak substitute, and there is a very weak complementary relationship with the oil group. Both of these effects are small compared with the degree of substitutability between energy and labor. In the industrial sector, all forms of energy are mutual substitutes. The most important substitute for electricity is natural gas. The degree of substitution between energy and labor is small compared with the commercial sector.

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[11] The effects of the oil embargo in 1974 are also estimated for the two oil equations. The names of the three coefficients estimated from the average time-series end with an "A" in Tables 2-6, 2-7, and 2-8.

[12] The data problems that exist at the state level tend to cancel out in the average time-series because some of the discrepancies in the oil data relate to allocating quantities among states.

Table 2-10
ECONOMIC CHARACTERISTICS OF THE FINAL MODEL: ESTIMATED LONG-RUN ELASTICITIES

Residential	PEL	PNG	POL	POM	PNF	INC
QEL	-0.30	0.04	0.16	-0.05	0.08	0.07
QNG	0.07	-0.21	0.04	-0.05	0.08	0.07
QOL	0.21	0.03	-0.34	-0.05	0.08	0.07
QOM	-0.02	-0.01	-0.01	-0.33	0.21	0.15
QNF	-0.01	-0.01	-0.01	-0.03	-1.01	1.07

Commercial	PEL	PNG	POL	POH	PLB
QEL	-0.65	0.03	-0.01	-0.01	0.63
QNG	0.12	-0.31	-0.22	-0.22	0.63
QOL	-0.02	-0.19	-0.60	0.18	0.63
QOH	-0.02	-0.19	0.17	-0.59	0.63
QLB	0.01	0.00	0.00	0.00	-0.02

Industrial	PEL	PNG	POL	POH	PCL	PLB
QEL	-0.55	0.34	0.06	0.06	0.07	0.03
QNG	0.52	-1.70	0.52	0.58	0.05	0.03
QOL	0.08	0.46	-0.86	0.27	0.03	0.03
QOH	0.08	0.46	0.24	-0.83	0.03	0.03
QCL	0.35	0.16	0.10	0.11	-0.75	0.03
QLB	0.00	0.00	0.00	0.00	0.00	-0.01

Q __ Quantity of __
P __ Price of __

EL	Electricity
NG	Natural Gas
OL	Oil (Light)
OH	Oil (Heavy)
OM	Oil (Motor)
CL	Coal
NF	Nonfuel
LB	Labor
INC	Income

The next step in the analysis is to determine how well the models predict actual experience. Since the form of the regression equation is in terms of the logarithm of an expenditure ratio, the fit of these equations is not of particular interest.[13] Furthermore, the fitted equations include coefficients that were subsequently set to zero. Hence, it is of more interest, and a more challenging test, to determine how well the quantities of fuels are predicted.[14] Since the models were estimated from a subset of states, the predictive performance is assessed separately from the states used for estimation and for those excluded. The objective is to determine whether the models reflect idiosyncratic properties of the estimation subset of states that are not generally applicable to all states. The results are summarized in Table 2-11.

The predictions are for the annual quantity used per capita in each state for the years 1967-79. The use of per capita units avoids exaggerating the fit of the models due to differences in the population.[15] Hence, the overall fit of the equations is very good for electricity, natural gas, and coal. Since the data in the oil series are not reliable, it is not surprising that the fits for the oil fuels are not as good. There is virtually no indication, however, that the performance of the non-oil equations deteriorates in the states not used for estimation. The overall conclusion is that the model performs well for all states, and the explanatory power of the equations for electricity, natural gas, and coal is high.

The final model was also used to project demand for the forecast period, 1980 through 2010. The results, which are presented in Section 2.4, below, provide further evidence on the sensitivity of the projections to the input specifications.

2.2.3 Load Characteristics

The sum of sales to all sectors in the AUSM demand module[16] is adjusted to account for distribution and other losses and for the interstate transfer of power. This provides the quantity of electricity that must be generated within each state. The main difficulty in this step is the treatment of interstate transfers. Many states belong to a power pool, and all plants in the pool are dispatched centrally. Since

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[13] Given the problems with measurement errors for oil quantities, there is no simple statistical test for comparing the fit of the models in the two subsets of states.

[14] The conversion from expenditure shared to quantities requires specifying income in the residential sector and employment levels in the commercial and industrial sectors.

[15] Two measures of fit are used. The first is the root mean squared error of prediction. This measures the size of a "typical" error, which can be compared to the mean level of use. The second measure is the Pseudo-R^2, which is positively related to fit, and is always less than one (perfect fit).

[16] The ratio of sales in the transportation sector to sales in the commercial sector in 1980 is treated as a state-specific parameter for determining how much electricity is used for transportation.

Table 2-11
SUMMARY OF THE PREDICTION PERFORMANCE OF THE ESTIMATED MODELS

	States Used for Estimation			States Not Used for Estimation			All States Combined		
Residential	*Mean*	*RMS*	R^2	*Mean*	*RMS*	R^2	*Mean*	*RMS*	R^2
QEL	9.01	0.33	.99	9.53	0.37	.99	9.40	0.36	.99
QNG	26.50	1.05	.98	19.26	1.19	.99	21.07	1.08	.99
QOL	22.99	3.25	.85	18.43	2.41	.96	19.57	2.64	.95
QOM	48.00	2.22	.97	48.82	2.96	.89	48.61	2.80	.92
Commercial									
QEL	7.26	0.40	.99	7.37	0.31	.98	7.35	0.33	.99
QNG	14.48	1.14	.96	9.59	0.74	.98	10.81	0.86	.98
QOL	6.83	1.75	.73	7.21	1.76	.93	7.12	1.76	.91
QOH	11.41	3.05	.82	10.58	2.43	.84	10.79	2.60	.83
Industrial									
QEL	9.67	0.30	.99	11.71	1.03	.98	11.28	0.93	.98
QNG	33.91	2.89	.97	37.86	6.53	.97	37.04	5.96	.97
QOL	12.55	3.20	.86	12.12	3.97	.87	12.21	3.83	.87
QOH	21.12	2.87	.82	23.20	5.27	.78	22.77	4.87	.79
QCL	34.63	4.53	.98	13.05	3.74	.98	17.54	3.92	.98

Mean = Average annual use (million Btu per/capita)
RMS = Root mean squared error of prediction (million Btu per/capita)

RMS = $\sqrt{\frac{1}{T}\sum_{t=1}^{T}(P_t - A_t)^2}$, where P_t and A_t are the predicted and actual values for year t.

R^2 = Pseudo-R^2 measuring the relative importance of the unexplained variability to the total variability of the actual series.

$$R^2 = 1 - \sum_{t=1}^{T}(P_t - A_t)^2 / \sum_{t=1}^{T}(A_t - \bar{A})^2$$

where $\bar{A}$ is the mean of $A_1, A_2, \ldots, A_T$.

Q __ Quantity of fuel or electricity per capita

See Table 2-10 for the fuel identification.

plans have been discussed to adapt the AUSM so that major dispatching regions can be used for dispatching and planning purposes, most effort has gone to getting suitable information about dispatching regions. The analysis at the state level is relatively simple.

A single average loss factor for the nation in 1980 is determined by comparing total sales net of exports with total generation net of imports. This factor is applied to total sales to ultimate customers in each state to give total required generation. The difference between actual generation and required generation in 1980 is treated as an additional state-specific factor accounting for interstate transfers.

Given an estimate of generation, additional load characteristics can be determined. Since the relevant load characteristics refer to the group of plants dispatched, this information is generally not available for states. The National Electric Reliability Council does provide information for council regions and subregions on the load factor and the ratio of summer to winter peaks. Projections of these characteristics are made annually [8]. Currently, the projected load factors are used for all states in the respective subregions. One interesting feature of these projections is that anticipated changes in the load factors are relatively small in all regions, suggesting that the relationship between generation and peak load is stable.

If the AUSM is modified to operate for groups of states within a single power pool, the model will be much more representative of actual practices in the industry. Interstate transfers within a dispatching region would then be determined by the model. If the model continues to operate exclusively at the state level, there is no simple way to deal with interstate transfers of power in anything but a cursory manner.

2.2.4 Demand Projections

The purpose of this component of the demand module is to approximate the way in which utilities forecast the future demand for electricity. The objective of the demand equations discussed above is to provide an accurate representation of how demand responds to economic factors. These equations could be used to derive forecasts of "future" demand for a given year in a simulation. However, this procedure would not account for any systematic bias in the way utilities forecast future demand. Consequently, a separate model is estimated using the actual projections of future demand published each year by the

National Electric Reliability Councils [8]. It is assumed that some form of adaptive expectations process exists by which utilities modify their forecasts as new information becomes available.

The importance of this adaptive process is illustrated in Figure 2-2 for the aggregate of all nine council regions. The forecasts of future levels of generation made in the years 1974-82 are shown together with the actual levels of generation. It is clear that there has been a tendency to overestimate the future growth of demand, and this has resulted in a substantial amount of capacity being built to meet demand levels that never materialized. Consequently, reserve margins are often much higher than the level required to meet reliability criteria. This is particularly true in northern and eastern states.

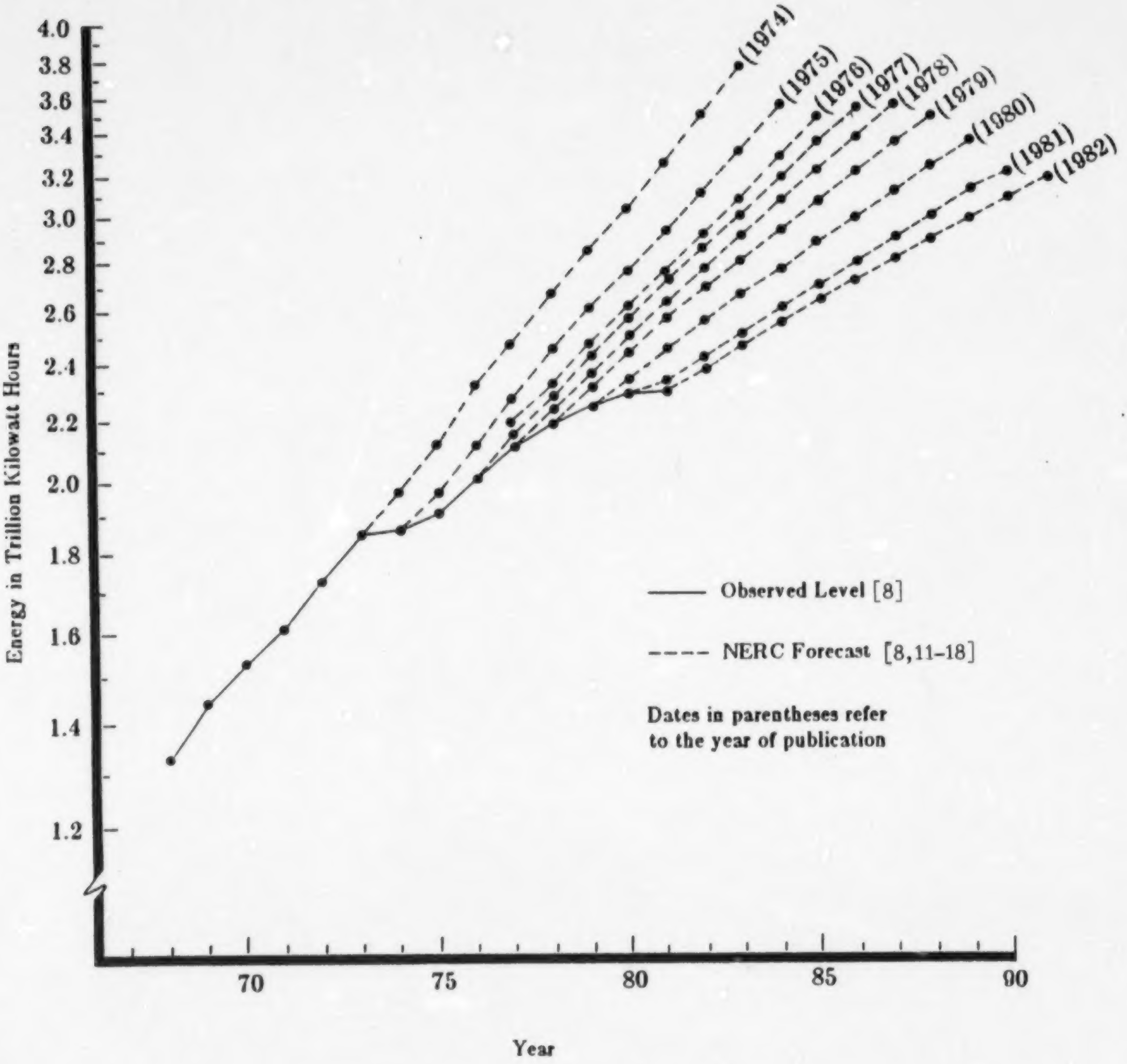
The existence of high reserve margins creates financial problems for utilities, particularly now when real interest rates are high and construction costs have escalated. Inclusion of an adaptive mechanism for projecting future demand is designed to reflect this type of problem. For example, if demand grows more slowly than expected because higher control costs are passed on to customers, financial problems are exacerbated. If demand growth is unexpectedly high, however, utilities may be short of capacity and have to resort to building peaking plants because there is insufficient time to build baseload plants. Both of these situations may have important consequences for controlling emissions through their influence on the financial status of utilities.

The following analysis is a summary of a more detailed study [9,10]. The model is designed to predict the average projected annual growth rate of demand for 15 years ahead of the current year. Demand is measured by energy requirements (generation) rather than peak load because energy is less sensitive to unusual weather conditions in the historical period. The explanatory variables are the actual growth rates for the four previous years. The underlying hypothesis is that the projected growth rate is a weighted sum of past growth rates, and the weights would be expected to be positive and decline so that recent experience has higher weights. The data set covers the years 1974-80 for the nine council regions.

Preliminary attempts to fit the model indicated that conditions immediately after the oil embargo in 1974 were treated differently from more recent events. Hence, a second form of adaptation was introduced into the model to reflect the effects of the oil embargo. The resulting model was subjected to a number of diagnostic tests to identify high leverage observations. When two observations had been

Figure 2-2

FORECASTS OF ELECTRIC ENERGY NEEDS IN THE UNITED STATES PUBLISHED BY THE NATIONAL ELECTRIC RELIABILITY COUNCILS (1974-82)



dropped from the sample, a satisfactory model was obtained. The results are summarized below:

$$
\begin{aligned}
(FR_t - AR_{t-4}) = {} & (.500 - .730/T)(AR_{t-1} - AR_{t-4})(7.14)(3.92) \\
& + (.250 - .242/T)(AR_{t-2} - AR_{t-4})(3.04)(1.02) \\
& + (.141 + .284/T)(AR_{t-3} - AR_{t-4})(2.47)(1.53) \\
& + \textit{regional effects} \qquad R^2 = .94 \qquad (27)
\end{aligned}
$$

where FR is the forecasted annual growth rate for 10 years ahead, AR is the actual growth rate, and T is the number of years after the oil embargo. The growth rates are expressed as differences from the observed rate lagged four periods (AR_{t-4}) to ensure that the weights sum to one, and the effects of the oil embargo sum to zero. This implies that the forecasted growth rate is a true weighted average in all years.[17]

The results imply that the weighting function changes over time. Immediately following the oil embargo, the observed low or negative growth rates were ignored for forecasting purposes. In other words, the adverse economic conditions were treated as a temporary phenomenon by electric utilities. Gradually, however, the model changes to a more economically rational form with declining weights. This asymptotic form is the part relevant for the forecast period with the AUSM. The change in the shape of the weighting function can be illustrated by considering the implied weights for the four lagged growth rates when t = 1 (1974) and when T = ∞.

	Estimated Weights	
Variable	*$T = 1$*	*$T = \infty$*
AR_{t-1}	-.230	.500
AR_{t-2}	.008	.250
AR_{t-3}	.425	.141

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[17] The regional effects are the coefficients for regional dummy variables, and they reflect a consistent practice of over- or underpredicting. These effects are phased out during the first five years of the simulation, implying that the methods used by utilities will no longer be biased after 1985.

AR_{t-4}	.797	.109

The overall effect of using a weighting function to make projections of future demand is that fluctuations in "actual" growth implied by the demand equations will be smoothed out. Furthermore, there will be a delay in the response of projections when the growth of actual demand departs from an established trend. This will introduce greater realism into the model by treating the financial problems of incorrect forecasting explicitly. These effects will, however, not be as dramatic as they were immediately after the oil embargo.

2.3 Data Choices

The econometric approach in the demand module means that the demand equations are estimated statistically from a sample of observations. An important principle for establishing this sample was that data should be collected from standard sources to the extent possible so that the series can be updated in the future. This makes it possible to appraise how close the model's predictions are to actual experience. Since any set of demand equations represents behavioral rather than physical relationships, it is sensible to establish procedures for evaluating a model's performance as new information becomes available. This can be done satisfactorily only if current values of the data series used for estimation are readily available.

The primary sources for data can be summarized as follows:

1. American Gas Association (natural gas)
2. Edison Electric Institute (electricity)
3. National Electric Reliability Councils (load characteristics)
4. U.S. Bureau of Economic Analysis (income, employment, wages, and population)
5. U.S. Department of Energy (oil, coal, and rates for electricity).

The basic data set covers the 48 contiguous states in the United States for the years 1964-80. Some information for the first three years could not be obtained, and some information for 1980 had not been released when the equations were estimated. Consequently, the sample period used for estimation was from 1967 through 1979.

Much of the effort needed to establish the data base for estimation was for checking accuracy and documentation. A more detailed description of the definitions of variables and the procedures used to transform raw data to form the variables used for estimation is found in a separate publication that will be a supplement to this documentation [11]. The basic objective was to provide a consistent set of data for every fuel and sector in common quantity units (million Btu per capita) and price units (dollars per million Btu). The use of common per capita units for all fuels made it easier to compare energy use across states and sectors and to identify aberrent observations.

An unexpected problem arose concerning the 1979 and 1980 data on oil quantities from the Department of Energy. A number of categories of oil use were redefined, and the continuity of these series over time was broken because no information is currently available for splicing the old and new series together. Analytical procedures had to be developed to overcome this problem (see Section 2.2) and to recalibrate the estimated demand equations for the new variable definitions in 1980. A second problem was that population and employment series were revised by the Bureau of Economic Analysis (BEA) after information from the 1980 census became available. These revisions tended to create delays in the availability of data.

From the beginning of the project, a major goal was to develop an accurate, well-documented data base, organized so that it would be readily available to other users. Procedures were developed to ensure that this goal would be met. For example, to increase accuracy, data were entered directly into computer files by one person and checked by two other people for accuracy, changes in units, typographical errors in the source, and so on. In addition, plotting capabilities were used to generate time-series plots of each variable for each state. These plots were then checked to detect major discontinuities in the series.

In the software system used for estimating the demand equations, each data file contains on-line documentation in the form of comments. Each comment contains a descriptive title for the file as well as a notation of the units used, the source of the data, its range, and its periodicity. In addition, where there are irregularities in the source or other kinds of unusual situations, this is explained in a note in the comment. Aggregate variables contain machine-generated comments that describe how the data were derived and which raw variables were used. This provides an "audit trail" linking the variables used for estimation to the published sources of the raw data.

2.4 Stand-Alone Module Results

The estimated demand module has been used to make projections over the forecast period 1980-2010 for all three sectors. These results are presented to illustrate the economic implications of the models. Four scenarios have been specified. The first is a base case, and the other three represent a sensitivity analysis of the three major input characteristics: prices of electricity, prices of primary fuels, and income and employment. The four scenarios are:

A. *Base scenario.* This corresponds to growth rates of 3 percent for oil prices (natural gas prices increase to the price of oil in 1985 and then grow at the same rate), 2.25 percent for electricity, and 1.5 percent for coal (fixed at half the rate of oil prices). Total income, employment, and earnings, corresponding to the BEA projections for New York State, increase moderately at roughly 2.1 percent.

B. *High price of electricity* (4.5 percent growth)

C. *High price of oil* (6 percent growth)

D. *High economic growth* (+ 1 percent income, + .5 percent employment, and + 1 percent earnings).

The projected quantities of electricity and fuels demanded in 1990 and 2000 are summarized in Table 2-12. The projections for electricity are also illustrated in Figures 2-3 through 2-6. The total use of oil and natural gas declines in Scenario A, and the use of coal increases. Electricity demand increases slightly and then remains approximately constant. In Scenario B, with higher prices for electricity, the demand for electricity declines in all sectors, and the demand for primary fuels increases slightly. In Scenario C, with higher prices for oil, electricity demand increases, especially in the industrial sector, while the demand for primary fuels decreases. In Scenario D, with higher economic growth, the demand for electricity and all fuels increases.

Some of the economic features are illustrated by inspection of the projection of the demand for electricity in Figures 2-3 through 2-6. First, there is a substantial range in the projected levels of total demand–from over 26 million Btu per capita to less than 17 million Btu per capital. In other words, elec-

Table 2-12
SUMMARY OF PREDICTED DEMAND LEVELS FOR ELECTRICITY AND PRIMARY FUELS
(in million Btu per capita)

	1980	1990				2000			
		Scenario				*Scenario*			
	A	A	B	C	D	A	B	C	D
Residential									
Electricity	6.2	5.9	5.7	6.2	6.0	5.2	4.7	5.6	5.3
Natural Gas	19.0	17.4	17.6	16.4	17.7	16.7	17.1	14.8	17.0
Oil (light)	19.5	21.6	22.3	19.5	21.9	20.3	21.8	16.6	20.7
Oil (motor)	30.5	25.5	25.4	23.5	26.0	19.8	19.7	16.7	20.5
Commercial									
Electricity	8.0	8.3	7.8	8.3	9.0	8.3	7.0	8.3	9.7
Natural Gas	6.0	4.2	4.2	3.6	4.5	3.5	3.6	2.4	4.1
Oil (light)	5.2	4.3	4.3	3.8	4.6	3.8	3.8	2.9	4.1
Oil (heavy)	10.2	9.4	9.4	8.1	10.1	8.1	8.1	5.8	9.5
Industrial									
Electricity	6.7	9.2	8.3	10.4	9.7	9.4	7.5	12.2	10.4
Natural Gas	6.6	3.4	3.7	3.0	3.5	3.1	3.8	2.4	3.4
Oil (light)	6.0	5.0	5.1	5.0	5.3	4.9	5.1	4.7	5.5
Oil (heavy)	17.8	11.9	12.1	11.0	12.6	10.7	11.0	9.3	11.9
Coal	9.2	12.8	13.7	12.9	13.6	13.8	15.8	13.8	15.3
Total									
Electricity	21.0	23.4	21.8	24.9	24.7	22.9	19.2	26.2	25.5
Natural Gas	31.6	25.0	25.5	23.0	25.7	23.3	24.5	19.5	24.5
Oil (light)	30.7	30.9	31.7	28.3	31.8	29.1	30.7	24.2	30.7
Oil (heavy)	27.9	21.3	21.5	19.1	22.8	18.8	19.1	15.2	21.4
Oil (motor)	30.5	25.5	25.4	23.5	26.0	19.8	19.7	16.7	20.5
Coal	9.2	12.8	13.7	12.9	13.6	13.8	15.8	13.8	15.3

Scenarios
A = Base case
B = High price for electricity
C = High price for primary fuels
D = High economic growth

Figure 2-3
PROJECTED DEMAND FOR ELECTRICITY, ALL SECTORS

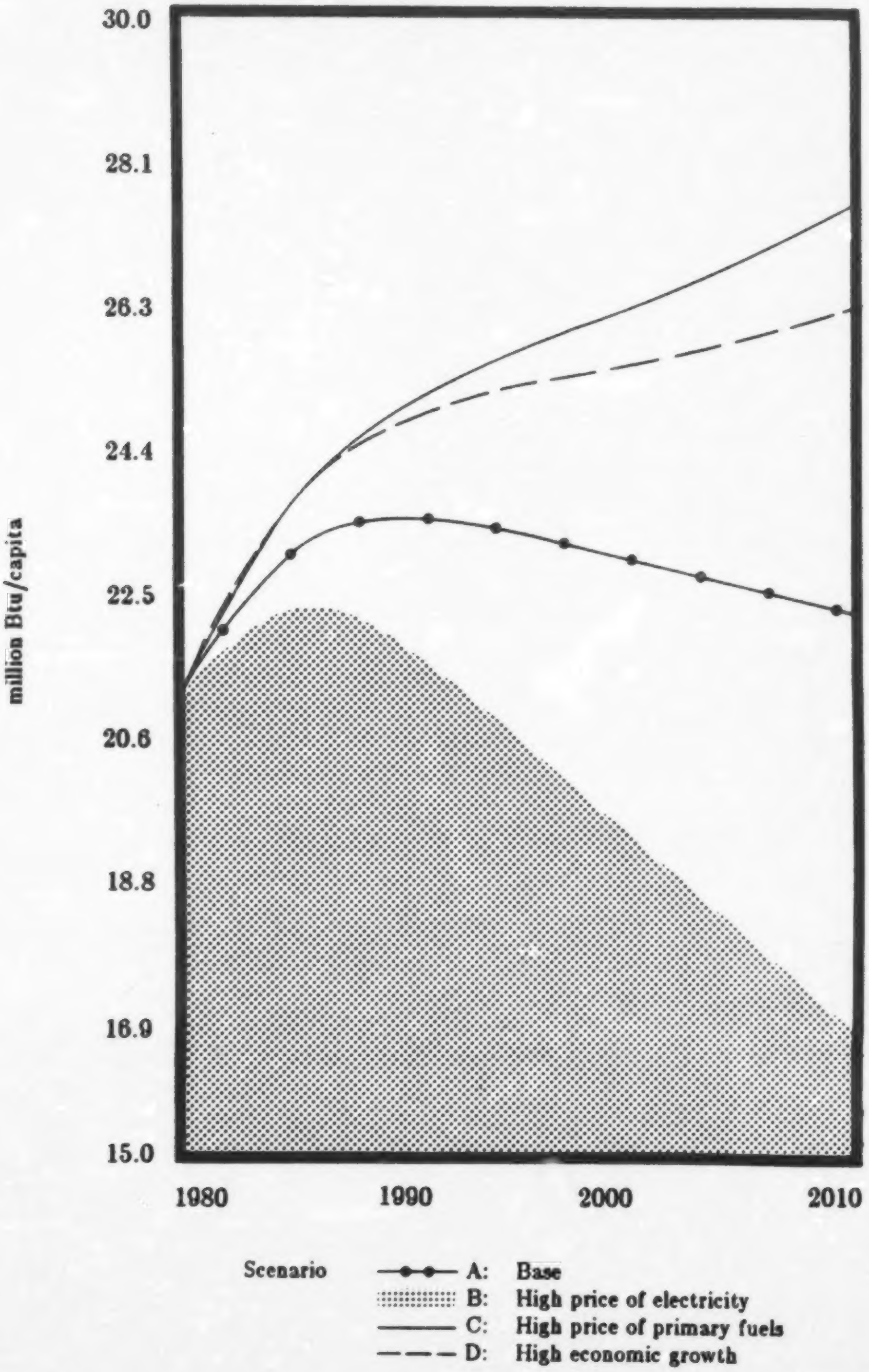


Figure 2-4
PROJECTED DEMAND FOR ELECTRICITY, RESIDENTIAL SECTOR

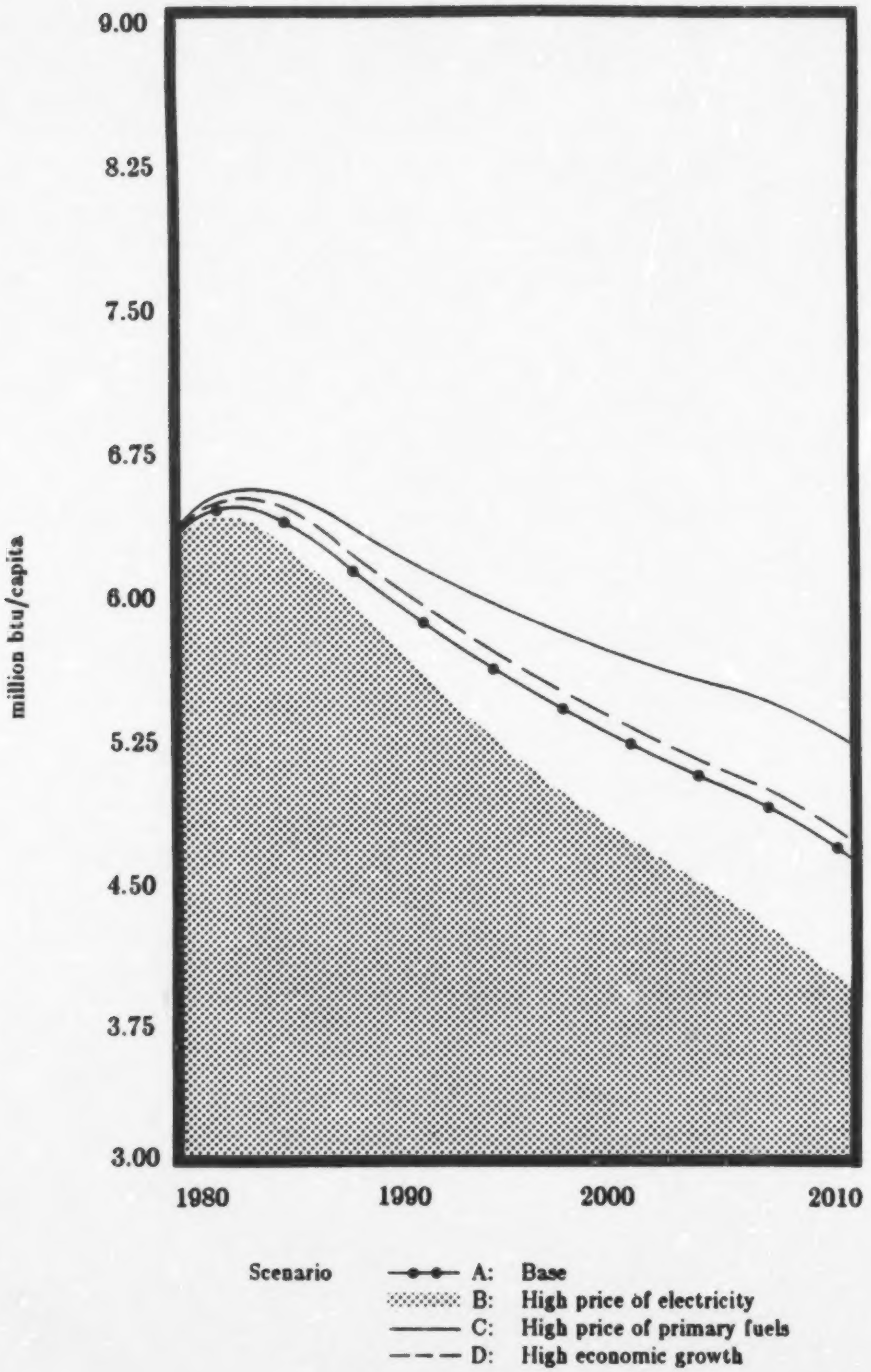


Figure 2-5

PROJECTED DEMAND FOR ELECTRICITY, COMMERCIAL SECTOR

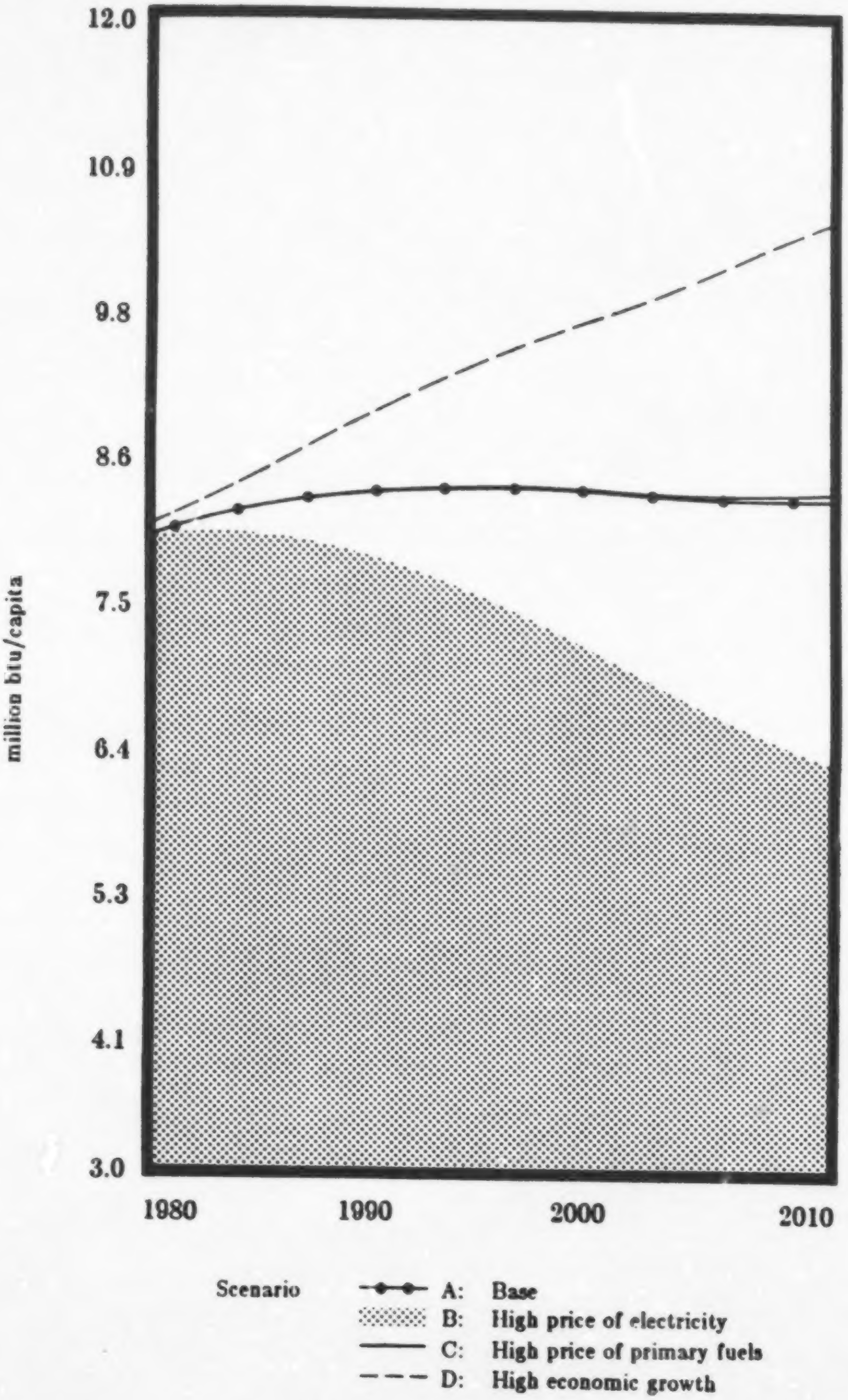
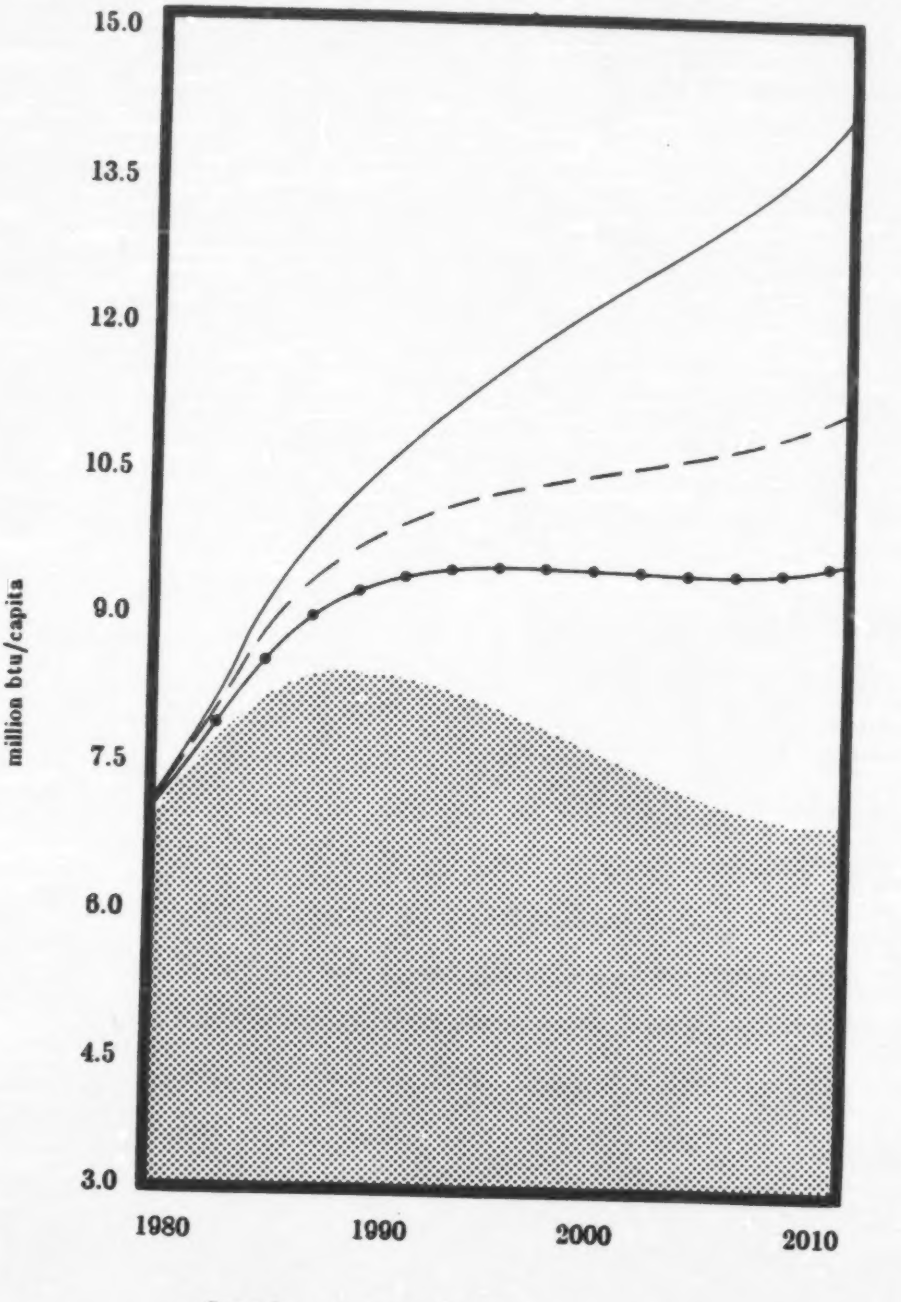


Figure 2-6

PROJECTED DEMAND FOR ELECTRICITY, INDUSTRIAL SECTOR



Scenario
- —●—●— A: Base
- ▨ B: High price of electricity
- —— C: High price of primary fuels
- – – – D: High economic growth

tricity demand is sensitive to economic conditions. Demand in the residential sector is the least responsive. The slight decline (note that the vertical scales differ in the four figures) can be attributed to switching expenditures away from energy as it becomes more expensive. In the commercial sector, the substitution of primary fuels for electricity is small, but this sector is responsive to growth. In the industrial sector, substitution among fuels is more important and growth less important than in the commercial sector.

The response of demand to higher prices for electricity is important in all three sectors. Although doubling the price of electricity is unlikely to occur in practice with other fuel prices unaffected, it should be remembered that the price of electricity represents a marginal and not an average price. In other words, price increases related to fuel could result from moving to incremental cost prices as well as to the additional costs associated with controlling emissions. Hence, in spite of the fact that the price elasticities for electricity are relatively small, compared with other studies, prices still have a substantial effect on the future demand for electricity.

2.5 Summary and Conclusions

The four major components of the demand module are all operational. The first component, updating rate schedules, is at the present time a simple mechanism that distinguishes between fuel and nonfuel costs. While this approximates current practices, it need not result in the implementation of economically efficient schedules. The distinction made between the marginal price and the customer charge when representing a rate schedule makes it possible to consider the use of efficient rate schedules, such as incremental cost pricing. It would also be possible to ensure that revenues cover costs and provide a "fair" rate of return to investors within this framework. More complicated rate setting procedures such as time-of-day rates can be approximated only in an annual model, such as the AUSM. The effects of setting time-of-day rates would have to be treated as a scenario specification. Since these rates imply that the characteristics of the system's load will change as demand is moved from on-peak to off-peak periods, it will be important to determine how sensitive other components of the model are to such changes.

Satisfactory demand models for the residential, commercial and industrial sectors have been estimated. These equations are dynamic, and their properties are consistent with economic logic in both the short run and the long run. Consequently, the implied elasticities are not constant, but change as the relative importance of expenditures on energy changes. This property ensures that predicted demand levels are non-negative and that predicted expenditure shares sum to one.

An additional step in developing the demand equations will be to simplify the way in which users of the model can specify different scenarios relating to the prices of primary fuels and to economic growth. It is also possible for users to specify the growth of demand exogenously for a base run, and then to investigate alternative scenarios against that specified base, with demand responding to price changes.

The component on load characteristics will develop in accordance with the way in which the national-level model is structured. At the present time, the model operates at the state level. If, however, groups of states belonging to the same power pool are treated together for planning and dispatching purposes, additional load characteristics can be specified for each power pool. Information on projected transfers of power among major power pools is currently being assembled using data from the regional electric reliability councils. The need for load characteristics other than energy and peak load will depend on how sensitive other components of the model, such as emissions, are to these characteristics.

The component that projects future demand in the demand module has been completed. This component is based on an adaptive mechanism to approximate the way in which utilities modify their forecasts as new information becomes available. This model provides a good fit to the forecasts made by the electric reliability councils during the mid and late 1970s. The implications of the model are that adjustments to changing economic conditions will be faster than they were after the oil embargo in 1974.

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3. THE FINANCIAL MODULE

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3.1 Introduction

The primary function of the financial module in the Advanced Utility Simulation Model (AUSM) is to provide quantitative responses to these kinds of questions: How much will air quality control costs affect rates and usage for consumers of electricity? How will they affect the financial condition of electric utilities? Developing reasonably accurate estimates of these effects is important because both consumers and utilities have had difficulty adjusting to the era of greatly increased energy costs that began in 1973. Business and residential customers, facing higher energy bills and economic recession, responded in part by using less electricity, particularly in the industrial Middle West. At the same time, many utilities had begun large construction projects in times of great demand growth and were struggling to complete these projects in a period of extremely high interest rates and inflation. Further, in the industrial regions of the country, the cost of the expensive new plants is being spread over fewer units of electricity demand, resulting in even higher rates. Thus, a financial module should compute the revenue requirement by which regulators determine rates and the financial statements that measure a utility's economic health. Ideally, the module should be embedded in an annually recursive model that captures the feedback effects between prices, demand, fuel use, air pollution emissions and future planning.

The acid precipitation problem, for example, requires this kind of modeling approach. A report prepared by the Department of Agricultural Economics at Cornell University [1] asserts that states often identified as major sources of pollutant precursors have been severely affected by economic recession and, as a result, declining electricity demand. Also, these states contain a number of utilities which are in financial difficulty. That report, which examines financial data on utilities and estimates of pollution control costs, could identify states or regions that might have particular difficulty bearing these costs, but it could not accurately estimate the magnitude of these effects on consumer rates or on a utility's financial status. This suggests the value of a module that not only calculates incremental costs of pollution control strategies but also integrates them into a utility's existing financial and regulatory situation.

The two principal existing utility models are the Utility Simulation Model (USM), developed by Teknekron Research, Inc. [2], and the Coal and Electric Utility Model (CEUM), developed by ICF, Inc. [3]. The CEUM is inadequate to these tasks, partly because it aggregates to a multistate level and is, therefore, unable to reflect the differences in state policies that determine electric rates. Our review of these state policies illustrates their complexity and diversity [4]. The CEUM does not use actual state financial data or the revised corporate income tax.

The USM performs its national and regional aggregations from state-level analyses; it provides detailed financial data and performed well in predicting late-1970s values of utility financial statements. However, the data base and the treatment of income taxation need updating. Most significantly, the USM financial module would have required complete restructuring to operate in annual interactions with demand and planning information.

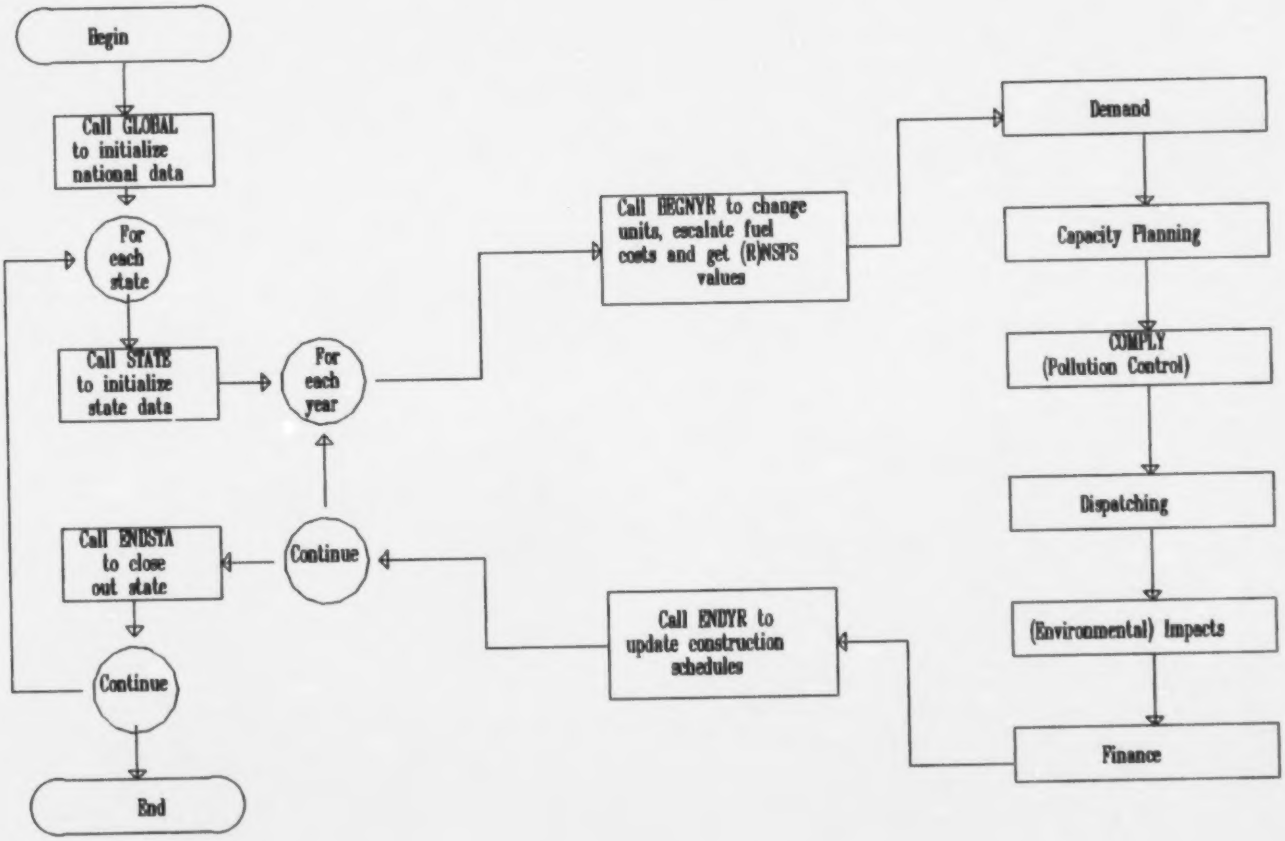
We decided, therefore, to develop an AUSM financial module. It is based in part on plant-level models we had constructed earlier to compute the costs of service of different types of generating facilities under various options for tax and regulatory policies [5,6,7]. These models compute the facility's annual increment to the cost of service over its operating life. The price computation is set out clearly, and policy options may be specified exogenously. The models also provide some financial measures such as the cash flow and profit attributable to the facility. These early Cornell plant models provide the basis for regulatory determination of revenue requirements in the AUSM financial model. The tax and financial statements modeling originated as part of the AUSM.

3.1.1 The Place of the Financial Module in the AUSM

The financial model in the AUSM has two major subroutines. FINANC analyzes revenue requirements and is part of the annually recursive interactive AUSM cycle. This is shown in Figure 3-1, taken

Figure 3.1

AUSM LOGIC FLOW


Begin
Call GLOBAL to initialize national data
For each state
Call STATE to initialize state data
For each year
Call BEGNYR to change units, escalate fuel costs and get (R)NSPS values
Demand
Capacity Planning
COMPLY (Pollution Control)
Dispatching
(Environmental) Impacts
Finance
Call ENDYR to update construction schedules
Continue
Call ENDSTA to close out state
Continue
End

from Reference 8. The second major financial subroutine is R602, which is part of the postprocessor AUSMR; it issues the financial reports and makes various financial analyses that follow from the interactive cycle.

The AUSM demand module determines many of the initial conditions of the other models and, therefore, executes first. It uses information from FINANC to set new electricity rates. Using these rates and information on fuel prices and other economic conditions, it estimates electricity demand for that year and adjusts electricity sales to reflect losses and transfers. It passes purchased power costs and total revenues, based on these rates and estimated sales, to FINANC; it passes generation and peak load net of transfers to the dispatching module (DSPACH). It also predicts the system load 10 years in the future and passes this information to the capacity planning module (PLAN). PLAN develops the utilities' construction schedules--their cost and timing--and it may modify these schedules based on the discrepancies between old and new sales forecasts received from DEMAND. It supplies construction costs and data for new generating facilities to FINANC, DSPACH, and COMPLY (pollution control). The COMPLY module chooses pollution control strategies and passes their costs and other characteristics to FINANC. DSPACH determines the amount of electricity supplied by each facility and, thus, the fuel and other operating costs for the year. IMPACT (also part of pollution control) produces estimates of the environmental effects of these decisions.

Thus, FINANC receives purchased power costs, construction costs for new generating facilities, construction costs for new pollution control equipment, and fuel and operating expenses. From these, it computes revenue requirement: the amount of revenue a state regulatory commission will allow its utilities to earn in that year. R602 uses the actual yearly revenues from DEMAND, together with many of the variables from FINANC, to compute entries for the standard financial reports--income statement, balance sheet, and funds flow--and for detailed statements on retained earnings, the corporate income tax, and the components of revenue requirement. It also computes interest coverage and profitability measures and prints these reports, samples of which are included in this chapter. FINANC passes its calculated revenue requirement to DEMAND, where it helps determine the following year's electricity rate schedule.

FINANC distinguishes seven different categories of assets for the purpose of computing depreciation schedules, including new and retrofitted pollution control equipment. It can accept data on individual units, plants, or even aggregations of plants as long as the aggregations are of the same type of asset, come on-line in the same year, and (in the case of new plants) have the same construction period. The major accounting variables are developed on an asset-by-asset basis for new construction. The model currently assumes that a state applies policies uniformly to all utilities and assets.

3.2 Analytical Structure

3.2.1. FINANC and the Determination of Revenue Requirement

Regulatory determination of allowed revenues and cost of service has become increasingly complex. This is primarily because of the growing intricacy of investment incentives in the Internal Revenue Code and the regulatory response in determining the distribution of those tax benefits over time and between customers, investors, lenders, and management. The following discussion assumes a prior knowledge of utility economics in general and cost of service and tax normalization in particular.[1]

To understand how the revenue requirement is determined in the model, we shall begin with the equation for it:

$$REVRQ_t = (SUMM_t + RD_t + RC_t + RP_t + RBDP_t + TF_t + TS_t) * (1 + (GRTXR * (1 - ETXR))). \tag{1}$$

This is the basic outline of the revenue allowance in Table 3-1. SUMM is the total of purchased power costs, fuel costs, operating and maintenance expenses, and non-income taxes. RD, RC, and RP are allowed returns to debt and to common and preferred equity. RD, for example, is computed by

$$RD_t = ADJRBS_t * RINT_t * DTPC \tag{2}$$

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[1] Introductory discussion of the revenue requirement concept and its relationship to customer rates and taxation with numerical illustrations is available in Chapter 12 of Reference 9.

TABLE 3-1

AUSM REGULATORY ECONOMICS

```
SCENARIO:        *** AUSM ***            *** AUSM ***                          OCTOBER  (::::::::)
                 *** AUSM ***        STATE LEVEL MODEL-SINGLE STATE            *** AUSM ***

AUSM REPORT - 602: FINANCIAL SUMMARY


 NORTH CAROLINA     (37)


REGULATORY  ECONOMICS     (ALL VALUES  IN MILLIONS OF CURRENT DOLLARS)

                   1980     1981     1982     1983     1984     1985     1986     1987     1988     1989

GRSS RATE bASE   11213.   11956.   12674.   13203.   14057.   14299.   15900.   16064.   16241.   16437.

RATE BASE ADJS
 CUM DEPREC       2045.    2285.    2558.    2893.    3243.    3629.    3988.    4477.    4940.    5407.
 CUM DEF ITC       316.     360.     442.     639.     672.     742.     716.     837.     807.     778.
 CUM DEF TAXES     856.     907.    1022.    1249.    1506.    1760.    1967.    2302.    2634.    2936.
         TOTAL    3216.    3552.    4022.    4782.    5421.    6131.    6671.    7615.    8381.    9120.

NET RATE BASE     7997.    8404.    8652.    8421.    8636.    8168.    9229.    8449.    7859.    7316.

REVENUE ALLOWANCE
 FD INC TX ALL     458.     553.     556.     529.     516.     475.     553.     424.     286.     264.
 ST INC TX ALL      64.      77.      77.      73.      72.      66.      77.      68.      54.      50.
 RETURN-DEBT       356.     402.     420.     418.     429.     413.     466.     453.     421.     392.
 RETURN-COMMON     407.     504.     519.     505.     518.     472.     554.     507.     472.     439.
 RETURN-PREF        90.     102.     105.     104.     105.     100.     110.     108.      94.      84.
 DEPRECIATION      204.     222.     253.     314.     332.     350.     359.     456.     459.     463.
 PROPERTY TAX       92.     100.     145.     198.     203.     215.     207.     272.     266.     259.
 GRREC TAX ALL      12.      15.      15.      17.      17.      18.      21.      21.      21.      21.
 OTHER TAXES        23.      26.      30.      33.      36.      37.      40.      46.      48.      49.
 FUEL-COAL         811.     872.     860.     796.     935.     890.    1363.    1349.    1419.    1470.
 FUEL-NUCLEAR       67.      72.     134.     204.     218.     233.     247.     316.     323.     324.
 FUEL-DIST OIL      36.      37.      24.       9.       9.      10.      43.      43.      42.      40.
 FUEL-RES. OIL       0.       0.       0.       0.       0.       0.       0.       0.       0.       0.
 FUEL-NAT. GAS      63.      75.      88.      63.      72.      83.     147.     152.     145.     126.
 FUEL-OTHER          0.       0.       0.       0.       0.       0.       0.       0.       0.       0.
 PURCH POWER      -161.      44.    -125.     116.    -126.     272.    -281.    -358.    -349.    -348.
 PLANT MAINT       158.     169.     195.     215.     243.     244.     329.     364.     392.     421.
 P. C. MAINT        16.      17.      17.      18.      21.      21.      32.      33.      35.      37.
 OTHER MAINT       183.     197.     215.     228.     259.     260.     358.     386.     417.     450.
 ADMIN,OTH EXP     404.     433.     474.     502.     571.     572.     790.     852.     919.     992.
         TOTAL    3282.    3916.    4003.    4344.    4430.    4739.    5416.    5492.    5465.    5533.
```

where ADJRBS is the adjusted rate base, RINT is the interest rate (the rate of return allowed for debt), and DTPC is the percentage share of debt in the utility's capital structure. RP and RC are computed analogously. The allowed rates of return for debt and equity are exogenous and remain constant throughout the simulation period. Since the general inflation rate is also constant over this time span, these correspond to constant real rates of return. RBDP is straight-line depreciation of the unadjusted rate base; it equals the sum over all assets of each asset's book value divided by its book life. TF and TS are allowances for the utility's federal and state corporate income tax expense.[2] The sum of these components is then multiplied by (1 + (GRTXR * (1 - ETXR)) to allow the utility to recover the gross receipts tax. GRTXR is the gross receipts tax rate, and ETXR is the effective state and federal combined corporate income tax rate, reflecting the fact that the gross receipts tax is a deduction for income tax purposes.

Certain components of required revenue account for most of the model's computations and need further explanation: rate base, both unadjusted and adjusted, and the tax allowance terms.

3.2.1.1 Cwip in the Rate Base and Original Cost Valuation.

The unadjusted rate base in the model consists of those assets that are used and useful (roughly, those currently in service), valued at their original cost. In most cases, this definition is accurate, but a few states in the Acid Rain Mitigation Study (ARMS) region adjust the value of the rate base for inflation, and a number have begun to allow the inclusion of some or all of construction-work-in-progress (cwip) in the rate base. Of the 32 ARMS-region states, 25 have at times allowed cwip in the rate base: 11 routinely allow 100 percent and 14 permit a smaller percentage, usually on a case-by-case basis [4]. The module allows for 100 percent of cwip in the rate base in states with this policy, as discussed in appropriate sections below. In this option, construction expenses augment the rate base in the year they are incurred. However, the assets do not begin to depreciate and are therefore not transferred to the gross plant and tax basis accounts until they come on-line.

Given the extremely long lead time for new plants and the high interest rates of recent years, earning a return on a project while it is still under construction is a considerable boon to utilities. Critics

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[2] Table 3-2 is a glossary of program variable names referred to in this chapter. The program documentation for the financial module [10] contains a complete glossary.

Table 3-2
GLOSSARY OF VARIABLE NAMES

Variable	Unit	Description
ACCTR	Million $	Accounts receivable; combines with CASH to make ASSCAO
ACITC	Million $	Accumulated investment tax credits for regulatory commission purposes (for deduction from the rate base); may be only a Fraction of total accumulated investment tax credit from electric investment or may equal zero; appears in the output on the regulatory economics statement
ACTCT	Million $	Accumulated total investment tax credit for all investments; appears in the output on the balance sheet
ADDE	Million $	Total direct construction costs and afudc charges in a given year excluding pollution control equipment; appears in the output on the statement of funds provided and funds applied
ADDP	Million $	Total direct construction costs and afudc charges for pollution control equipment in a given year; appears in the output on the statement of funds provided and funds applied
ADFBK	Million $	Accumulated total deferred income taxes for book purposes; equals accumulation of accelerated depreciation (construction cost, tax life) minus straight-line depreciation (construction cost, operating life) times tax rate; accumulated over assets as well as over time; appears in the output on the balance sheet
ADFRGE	Million $	Accumulated deferred income taxes for deduction from rate base; equals accumulation of TXDEPR minus REGDPE times the tax rate; accumulated over assets as well as over time; appears in the output on the regulatory economics statement

Table 3-2 (contd.)

Variable	Unit	Description
ADJRBS	Million $	Adjusted rate base; TOTRBS minus accumulated deferred taxes (ADFRGE) and accumulated investment tax credits (ACITC) in the normalization case; for flow-through accounting, ADJRBS equals TOTRBS; appears in the output on the regulatory economics statement
ADPRBE	Million $	Accumulated straight-line depreciation (construction cost plus afudc, operating life); accumulated over all facilities and over time; appears in the output on the balance sheet
AFDCD	Million $	Afudc-debt for a particular asset in a given year
AFDCE	Million $	Afudc-equity for a particular asset in a given year
AFUDCD	Million $	Afudc-debt accumulated over all projects under construction in a given year; appears in the output on the income statement and on the statement of funds provided and funds applied
AFUDCE	Million $	Afudc-equity accumulated over all assets under construction in a given year; appears in the output on the income statement and on the statement of funds provided and funds applied
AITC	Million $	Yearly amortization of the accumulated investment tax credit that is deducted from rate base in normalized accounting
ASSCAO	Million $	Current and other assets; equals ACCTR + CASH; appears in the output on the balance sheet
BSWCAP	Million $	Base year working capital; equals $ASSCAO_1$ - $LIACAO_1$
CAPTOT	Million $	Total capitalization; equals COMTOT + PEQTOT + LTDTOT
CASH	Million $	Cash; combines with ACCTR to make ASSCAO; will be greater than zero only if all debt has been retired

Table 3-2 (contd.)

Variable	Unit	Description
CCO	Million \$	Direct construction costs of an asset; used in setting up the depreciation accounts
CDIV	Million \$	Dividends paid on common stock; in most years equals 0.15 * RETBEG, but may be larger if utilities have excess funds; appears in the output on the retained earnings statement and on the statement of funds provided and funds applied
CEQPC	Fraction	Fraction of capitalization that is common equity
CEQTOT	Million \$	Total common stock issued; equals OLDCEQ + NWCEQ
CHAITC	Million \$	Change in investment tax credit shown on the balance sheet during the year; equals $ACTCT_t$ - $ACTCT_{t-1}$; appears in the output on the statement of funds provided and funds applied
CHWCAP	Million \$	Change in working capital during a year; if it is the first year of the simulation CHWCAP equals WCAP - BSWCAP; if it is a later year in the simulation CHWCAP equals $WCAP_t$ - $WCAP_{t-1}$; appears in the output on the statement of funds provided and funds applied
COMTOT	Million \$	Total common stock equity; equals CEQTOT + RETERN; appears in the output on the balance sheet
CONEXD	Million \$	Direct construction expense for distribution facilities in a given year
CONEXG	Million \$	Direct construction expense for general plant in a given year
CONEXP	Million \$	Direct construction expense for a particular generating facility or pollution control asset in a given year
CONEXT	Million \$	Direct construction expense for transmission facilities in a given year

Table 3-2 (contd.)

Variable	Unit	Description
CORR	Million $	Correction to total liabilities made for the first year balance of the balance sheet; appears in the output on the balance sheet
COV1...COV4		Interest coverage ratios; each of the four is computed by dividing a different definition of income by interest expense; appears in the output on the statement of interest coverage and profitability ratios
CRET	Fraction	Rate of return to common stock
CWIPE	Million $	Construction work in progress (construction cost plus afudc); equals CWPE + CWPP; appears in the output on the balance sheet
CWP	Million $	Construction work in progress (construction cost plus afudc); accumulated direct costs plus afudc for a particular asset in a given year
CWPE	Million $	Construction work in progress (construction cost plus afudc) for all non-pollution control electric assets under construction in a given year
CWPP	Million $	Construction work in progress (construction cost plus afudc) for all pollution control assets under construction in a given year
DBR	Fraction	Declining balance rate in effect in the year an asset comes on-line
DB1	Fraction	Temporary variable for calculating the accelerated depreciation basis when the declining balance method is used over the shortest ADR tax life
DB2	Fraction	Temporary variable for calculating the accelerated depreciation basis when the declining balance method is used over the normal operating life
DCEQ	Million $	Amount of common equity that would keep common equity, preferred equity, and debt levels in their original proportions of total capitalization

Table 3-2 (contd.)

Variable	Unit	Description
DDEBT	Million $	Amount of debt that would keep common equity, preferred equity, and debt levels in their original proportions of total capitalization
DEBTCH	Million $	Amount of debt to be retired in a year in addition to the amount of debt that reaches maturity in that year
DEN1	Million $	Denominator used in the computation of interest coverage ratios; equals LTDEXP
DEN2	Million $	Denominator used in the computation of profitability ratios one and two; equals COMTOT + PEQTOT
DEN3	Million $	Denominator used in the computation of profitability ratios three and four; equals NETPE
DFTXBK	Million $	Deferred tax for income statement; equals accelerated depreciation for all assets (construction cost, tax life) minus straight-line depreciation for all assets (construction cost, operating life) times the income tax rate; appears in the output on the income statement and on the statement of funds provided and funds applied
DNORME	Million $	Straight-line (construction cost plus afudc, operating life) depreciation on all electric assets in each simulation year; appears in the output on the income statement and on the statement of funds provided and funds applied
DOEXP	Million $	Direct operating expenses; equals PP + fuel costs + maintenance costs + OPEXPO; appears in the output on the federal income tax statement
DPEQ	Million $	Amount of preferred equity that would keep common equity, preferred equity, and debt levels in their original proportions of total capitalization
DPRATE	Fraction	Depreciation rate schedule under the new tax law for a particular asset

Table 3-2 (contd.)

Variable	Unit	Description
DRETIR	Million $	Debt to be retired in each simulation year (assumes 20-year bonds); appears in the output on the statement of funds provided and funds applied
DLS1	Million $	Straight-line depreciation (construction cost plus afudc, operating life) for a particular asset in a given year
DS3	Million $	Temporary variable for calculating straight-line depreciation
DTPC	Fraction	Fraction of capitalization that is debt
EQPC	Fraction	Fraction of capitalization that is equity; equals CEQPC + PEQPC
ETXR	Fraction	Combined effective federal and state corporate income tax rate; equals FTXR * (1 - STXR) + STXR
EXPTOT	Million $	Total operating expenses; equals DOEXP + DNORME + ITXR + GRTX + PTX + SSOTX; appears in the output on the income statement
FDAPPL	Million $	Total funds applied; equals ADDE + ADDP + DRETIR - AFUDCD - AFUDCE + PDIV + CDIV + CHWCAP; appears in the output on the statement of funds provided and funds applied
FDPROV	Million $	Total funds provided; equals NETINC + DNORME + DFTXBK - AFUDCD - AFUDCE + NWDT + NWCEQ + NWPEQ + CHAITC; appears in the output on the statement of funds provided and funds applied
FITX	Million $	Actual federal income tax expense; equals FTI * FTXR - ITC; appears in the output on the federal income tax statement
FNEEDS	Million $	Financial needs
FTI	Million $	Federal taxable income; equals OPREVE - SUMM - SITX - TXDEPR - LTDEXP; appears in the output on the federal income tax statement
FTXR	Fraction	Federal corporate income tax rate

Table 3-2 (contd.)

Variable	Unit	Description
GRSSPE	Million $	Gross electric utility plant in service; appears in the output on the balance sheet
GRTX	Million $	Gross receipts tax; equals OPREVE * GRTXR; appears in the output on the income statement and on the federal income tax statement
GRTXR	Fraction	Gross receipts tax rate
HADF	Fraction	Percentage of the total historic plant for a state using accelerated depreciation rather than straight-line depreciation for tax purposes
IAGEBK	Years	Age of historic gross electric plant that most closely approximates for book purposes the depreciation schedule as if the historic plant were a single asset with a 35-year life
ITC	Million $	Amount of investment tax credit earned during the year; sum of ZITC for each asset in each simulation year; appears in the output on the income statement and on the federal income tax statement
ITXP	Million $	Income tax paid; equals FITX + SITX; appears in the output on the income statement
ITXR	Million $	Income tax reported; equals ITXP + DFTXBK + ITC - TCTKN; appears in the output on the income statement
LIACAO	Million $	Notes and other current liabilities; appears in the output on the balance sheet
LIFN	Years	Operating life for a new asset
LIFT	Years	Tax life for a new asset
LTDEXP	Million $	Interest expense on long-term debt; equals RINT * LTDTOT; appears in the output on the income statement and on the federal income tax statement
LTDTOT	Million $	Total long-term debt; equals OLDT + NWDT

Table 3-2 (contd.)

Variable	Unit	Description
NETINC	Million $	Net income for income statement; equals OPREVE - EXPTOT + OTHINC - TOTINT; appears in the output on the income statement, on the retained earnings statement, and on the statement of funds provided and funds applied
NETPE	Million $	Net electric plant in service; equals GRSSPE - ADPRBE; appears in the output on the balance sheet
NWCEQ	Million $	New common stock issued; appears in the output on the balance sheet and on the statement of funds provided and funds applied
NWDT	Million $	New long-term debt issued; appears in the output on the statement of funds provided and funds applied
NWPEQ	Million $	New preferred stock issued; appears in the output on the balance sheet and on the statement of funds provided and funds applied
OLDCEQ	Million $	Common stock issued prior to each simulation year; appears in the output on the balance sheet
OLDPEQ	Million $	Preferred stock issued prior to each simulation year; appears in the output on the balance sheet
OLDT	Million $	Total outstanding debt as of each simulation year; equals LTDTOT_{t-1} - DRETIR_t
OPEXPO	Million $	Administrative, customer, and other costs; appears in the output on the income statement, on the federal income tax statement, and on the regulatory economics statement
OPREVE	Million $	Operating revenues; appears in the output on the income statement
OTHINC	Million $	Other income; equals AFUDCE; appears in the output on the income statement

Table 3-2 (contd.)

Variable	Unit	Description
PDIV	Million $	Dividends paid on preferred stock; equals OLDPEQ * PRET; appears in the output on the retained earnings statement and on the statement of funds provided and funds applied
PEQPC	Fraction	Fraction of capitalization that is preferred stock
PEQTOT	Million $	Total preferred stock; equals OLDPEQ + NWPEQ; appears in the output on the balance sheet
PP	Million $	Cost of purchased and interchanged electric power; appears in the output on the income statement and on the regulatory economics statement
PRET	Fraction	Rate of return to preferred stock
PROF1...PROF4	Fraction	Profitability ratios; computed by dividing different definitions of income by total equity for PROF1 and PROF2 or by dividing income by net plant for PROF3 and PROF4; appears in the output on the statement of interest coverage and profitability ratios
PTX	Million $	Property taxes: equal to TBASE * PTXR; appears in the output on the income statement, on the federal income tax statement, and on the regulatory economics statement
PTXR	Fraction	Property tax rate
RADCD	Fraction	Afudc-debt rate; equals RINT * DTPC
RADCE	Fraction	Afudc-equity rate; equals ROE * EQPC
RBDP	Million $	Straight-line depreciation (construction cost plus afudc, operating life); a component of revenue requirement
RC	Million $	Allowed return to common equity for revenue requirement determination; equals ADJRBS * CRET * CEQPC; appears in the output on the regulatory economics statement

Table 3-2 (contd.)

Variable	Unit	Description
RD	Million $	Allowed return to debt for revenue requirement determination; equals ADJRBS * RINT * DTPC; appears in the output on the regulatory economics statement
REGDPE	Million $	Depreciation deduction for regulatory commission tax allowance; for post-1080 assets it equals accelerated depreciation for all electric assets using construction costs and operating life
RETBEG	Million $	Retained earnings; beginning of year; equals RETERN_{t-1}; appears in the output on the retained earnings statement
RETERN	Million $	Retained earnings; end of year; appears in the output on the balance sheet and on the retained earnings statement
RETPCT	Fraction	Percentage of total common equity that is caused by retained earnings
REVRQ	Million $	Revenue requirement for price determination; appears in the output on the regulatory economics statement
RINT	Fraction	Interest rate on long-term debt
ROE	Fraction	Rate of return to equity for afudc and required revenue calculations; a weighted average of PRET and CRET
RP	Million $	Allowed return on preferred equity for revenue requirement determination; equals ADJRBS * PRET * PEQPC; appears in the output on the regulatory economics statement
STI	Million $	Taxable income for the purposes of calculating state income tax; equals OPREVE - SUMM - TXDEPR - LTDEXP
SITX	Million $	State income tax due in a given year: equals STI * STXR; appears in the output on the federal income tax statement
SOURCO	Million $	Other funds provided: equals FDAPPL - FDPROV; appears in the output on the statement of funds provided and funds applied

Table 3-2 (contd.)

Variable	Unit	Description
SSOTX	Million $	Social security and other taxes; equals a percentage of OPREVE
STXR	Fraction	State income tax rate for electric utilities
SUMM	Million $	Sum of fuel costs, operating costs, and non-income taxes
TBASE	Million $	Basis for tax depreciation and property tax; equals sum of direct construction costs for all plants on-line minus ADPTBE; for historical plant equals GRSSPE * TBSPC
TBSPC	Fraction	Fraction of historical gross plant exclusive of afudc
TCTKN	Million $	Amount of investment tax credit taken in determining income for book purposes; appears in the output on the income statement
TF	Million $	Federal income tax allowance for required revenue determination; appears in the output on the regulatory economics statement
TOTINT	Million $	Total interest expense for income statement; equals LTDEXP - AFUDCD; appears in the output on the income statement
TOTITC	Million $	Accumulated investment tax credit earned by a particular asset
TOTRBS	Million $	Rate base: construction costs plus afudc on electric plant in service, net of accumulated depreciation; equals GRSSRB - ADPRBE
TS	Million $	State income tax allowance for REVRQ determination; appears in the output on the regulatory economics statement
TXDEPR	Million $	Actual income tax deduction (usually accelerated depreciation (construction cost, tax life) in each simulation year on total assets; appears in the output on the federal income tax statement
TXDP	Million $	Actual income tax depreciation deduction (usually accelerated depreciation (construction cost, tax life)) for a particular asset in a given year

Table 3-2 (contd.)

Variable	Unit	Description
VEST	Million $	Accumulated direct construction cost for a particular asset
WCAP	Million $	Working capital; equals ASSCAO - LIACAO
ZITC	Million $	Investment tax credit earned by a particular asset in a given year
ZITCR	Fraction	Investment tax credit rate

charge that this kind of policy removes incentives for the utility to complete projects in reasonable periods of time and to keep costs down.

3.2.1.2 **Allowance for Funds Used During Construction (afudc).** If it is not included in the rate base until it comes on-line, the original cost of an asset consists of actual or direct construction costs and also an allowance, called afudc, which compensates utilities for the costs of the funds provided by both debt and equity holders to construct the plant. Thus, afudc is an accounting concept with an equity component, which appears on a utility's income statement under other income, and a debt component, which reduces actual interest expense in the computation of net income. These items therefore increase the utility's net income, but they do not represent monies that the company has actually received in that year.

In the financial module, afudc is computed in the sections that obtain and process new construction cost data for the year and also in the section that deals with base-year construction work in progress. In both cases, afudc is computed by multiplying the portion of the year's assumed construction costs financed by debt/equity by the rate of return to debt/equity. In the method used by most states, afudc is computed cumulatively, i.e., on the basis of accumulated construction costs, including previous afudc for the plant. In other states, the basis for computing afudc does not include previously earned afudc. The module allows either option, signalled by a state-specific variable.

While afudc increases the rate base, it is excluded from the basis on which tax depreciation is computed.

3.2.1.2.1 **Afudc for New Construction.** More specifically, the new construction cost portion of the model obtains data on that year's costs and on previous years' accumulated accounts on a plant-by-plant basis, adjusts the current year's costs for inflation, and then computes cumulative afudc as follows:

$$AFDCE = (CONEXP_t + CWP_{t-1}) * RADCE_t \tag{3}$$

$$AFDCD_t = (CONEXP_t + CWP_{t-1}) * RADCD_t. \tag{4}$$

Noncumulative AFUDC is computed

$$AFDCE_t = (CONEXP_t + VEST_{t-1}) * RADCE_t \tag{5}$$

$$AFDCD_t = (CONEXP_t + VEST_{t-1}) * RADCD_t. \tag{6}$$

If a state allows cwip in the rate base, the model does not compute afudc but adds construction costs into the rate base in that very year, leaving AFDCD and AFDCE at their initialized values of zero. Construction costs are still accumulated, however, since the assets will contribute to the gross plant and tax basis accounts only when they begin operation. Thus, in all cases,

$$CWP_t = CWP_{t-1} + AFDCE_t + AFDCD_t + CONEXP_t \tag{7}$$

$$VEST_t = VEST_{t-1} + CONEXP_t. \tag{8}$$

In these equations, AFDCE and AFDCD are the equity and debt portions of afudc; CWP is construction work in progress; VEST is accumulated direct construction cost; and CONEXP is that year's direct construction cost (all for that particular plant). When the asset is a new generating facility, CONEXP includes whatever construction costs were incurred for pollution control equipment on the plant. Direct construction costs for transmission, distribution, and general plant are designated by CONEXT, CONEXD, and CONEXG, rather than CONEXP. RADCE and RADCD are weighted average returns to debt and equity and are computed as follows:

$$RADCE_t = ROE_t * EQPC \tag{9}$$

$$RADCE_t = RINT_t * DTPC\,(1 - ETXR) \text{ or}$$

$$RADCD_t = RINT_t * DTPC. \tag{10}$$

RINT and ROE are the allowed rates of return to debt and equity. DTPC and EQPC are the shares of debt and equity in the capital structure and sum to one. EXTR is the combined effective federal and state corporate income tax rate. Here again is a policy option that reflects differences in states' computation of afudc. Some use a return that reflects the tax deductibility of interest, while others do not. (This option is signalled by a state-specific variable when RADCD and RADCE are computed in the first simulation year.)

Once the values are computed for a particular plant they are added into the aggregated afudc and cwip accounts for that simulation year:

$$AFUDCE_t = AFUDCE_t + AFDCE_t \tag{11}$$

$$AFUDCD_t = AFUDCD_t + AFDCD_t \tag{12}$$

$$CWIPE_t = CWPE_t + CWPP_t \tag{13}$$

$$ADDE_t = ADDE_t + CONEXP_t + AFDCE_t + AFDCD_t \tag{14}$$

$$ADDP_t = ADDP_t + CONEXP_t + AFDCE_t + AFDCD_t. \tag{15}$$

Here, CWPP and CWPE are accumulations of the variable CWP for retrofitted pollution control equipment and for other electric plant. ADDP and ADDE are the year's additions to retrofitted pollution control and other electric construction expense, including afudc. ADDE, except for its afudc component, is exogenous in the base year, since plant-specific data are not readily available for utilities' entire construction programs. The plant-specific cumulative variables are then stored in a data group to be retrieved in future years of the construction period.

3.2.1.2.2 **Afudc for Base Year Construction in Progress.** Another section of FINANC handles the accumulation of construction work in progress that is not accounted for by plant-specific data from the unit inventory file (see Appendix A). It is treated as a fossil-fuel generating facility of five units, one of which comes on-line in each of the second through sixth simulation years. In the second year, one-fifth of this cwip comes on-line; in the third year, one-fourth of the remaining cwip; in the fourth year, one-third of the remaining cwip; and so forth. The units incur no new construction expenses, but each year the portion of the plant not yet in use continues to accrue afudc. The equations are simular to those presented above, and AFDCD, AFDCE, and CWP are added into that year's aggregate accounts for all plants. If a state allows cwip in the rate base, the entire amount of this base year cwip is added to the rate base in the first simulation year, it does not earn afudc, and it is added into the gross plant accounts for book and tax purposes only gradually, as each unit comes on-line.

3.2.1.3 **Gross Plant and Depreciation Accounts.** In the year before a plant comes on-line, the program calls the subroutine DEPREC to compute yearly and accumulated book depreciation, tax depreciation, and deferred tax accounts for the new asset. When these values are returned, FINANC adds them to the appropriate aggregate arrays, beginning with the next simulation year, for new construction, and beginning with the current year, for base-year cwip units. In addition, the final value of CWP for the asset is added to the accounts for gross electric plant and to the gross rate base, GRSSPE and GRSSRB. The final value of VEST is added to the aggregate tax basis array, TBASE. Thus, as noted above, only actual construction costs, exclusive of afudc, enter into the basis for tax depreciation.

The values of GRSSPE, GRSSRB, and TBASE to which new assets are added are those for historical plant—facilities in service as of the first simulation year. These initial values are set at the beginning of the subroutine in a section which is executed only in the first simulation year. The actual state value for historical plant (which includes afudc) is assigned to the variable GRSSPE (gross electric plant), and the assumed proportion of gross plant that is due to direct construction costs is the initial value of TBASE. Detailed depreciation data are not available for existing generation, transmission, and distribution plant. Therefore, the model approximates depreciation accounts for historical plant as noted in appropriate sections below.

3.2.1.4 **Unadjusted Rate Base**. Finally, the unadjusted rate base in a given year (TOTRBS) equals GRSSRB minus accumulated straight-line depreciation (ADPRBE). Annual straight-line depreciation for one asset (DSL1) equals its final CWP value divided by its operating life; annual aggregate straight-line depreciation (RBDP or DNORME) is the sum of these values for all assets; and ADPRBE is the accumulation of DNORME over the years. For historical plant, accumulated straight-line depreciation is approximated by assuming an average operating life for electric plant of 35 years.

The rate base may be subject to further adjustments, depending on how the state regulatory commission treats utilities' use of certain corporate income tax deductions and credits. There is thus a close link between the tax allowance equations, TF and TS, and the equation for adjusted rate base, ADJRBS.

3.2.1.5 **Tax Depreciation**. In computing the actual corporate income tax paid by utilities, the model makes the most advantageous use of the federal income tax provisions for accelerated depreciation and the investment tax credit. Unlike straight-line depreciation, which provides equal deductions in each year of an asset's entire operating life, accelerated depreciation allows larger deductions in the early years and smaller ones later. In present value terms it is the preferred method. The two means of accomplishing such a depreciation schedule are (1) tax lives that are shorter than operating lives and (2) a depreciation rate that is greater than the straight-line rate. The Internal Revenue Service has allowed a variety of lives and rate formulas over the past few decades.

A portion of a state's assets placed in service before January 1, 1981 (historical base-year plant) is assumed to follow the tax depreciation provisions of the old version of the Internal Revenue Code. This specifies a range of allowable tax lives for each type of asset in the Asset Depreciation Range (ADR) System. The code permits a depreciation rate as much as twice the straight-line rate. Thus, for historical plant, tax depreciation deductions are computed as follows for the first half of an asset's life:

$$TXDP_t = (DBR_t/LIFT) * DB1_t * CCO. \qquad (16)$$

TXDP is tax depreciation for a particular asset (which is then added to the aggregate variable TXDEPR); DBR, the declining balance rate, equals 2.0; LIFT is the shortest life allowed under the ADR System; CCO is the original cost of the asset, exclusive of afudc; and DB1 is a fraction which adjusts CCO to reflect depreciation deductions already taken. CCO is further adjusted to conform to the half-year convention, whereby only half of an asset's basis may be depreciated in the first year. When half of the tax life is completed a straight-line depreciation of the remaining basis becomes advantageous.

However, many of a state's assets were placed in service in the 1950s and 1960s, when utilities frequently used straight-line depreciation for tax purposes. The model allows a fraction of assets (HADF) to use the ADR System such that the calculated accumulated deferred tax for the base year equals the exogenous value. Accumulated deferred tax equals ($TXDP_t$ - $DS3_t$) * ETXR, summed over t, where DS3 is straight-line depreciation computed on the tax basis, and ETXR is the effective state and federal corporate income tax rate. (1 - HADF) of the historical assets are then assumed to use straight-line depreciation for tax purposes. HADF is computed for the model as follows:

1. It calculates the age of the plant for book purposes (IAGEBK), assuming a 35-year life.
2. It computes the value of accumulated straight-line depreciation at IAGEBK (using the tax basis).
3. It calculates the value of accumulated accelerated depreciation at IAGEBK, using the ADR System.

4. It computes the actual accumulated accelerated depreciation for a state's utilities, at IAGEBK, equal to (2) + (actual base year accumulated deferred tax)/ETXR.

5. It calculates HADF = ((4) - (2))/((3) - (2)).

At present HADF is calculated for each state outside of the model and enters as data.

Major changes in this part of the Internal Revenue Code, enacted in 1981 and revised in 1982, significantly shorten the tax lives for public utility assets: from 22.5 to 15 years for steam generation plants (fossil-fired); from 24 to 15 for transmission and distribution facilities; from 40 to 15 for hydroelectric generating plants; and from 16 to 10 for nuclear generating facilities. In the initial version of the new law the depreciation rate was to be 1.5 times the straight-line rate for assets placed in service 1981-84, 1.75 in 1985, and 2.0 after 1985 (i.e., DBR could be 1.5, 1.75, or 2.0). A switch to the sum of the years' digits method[3] was allowed as soon as it became advantageous. Revisions to the code in September 1982 rescind some of the benefits: the rates for 1981-84 apply for later years as well. Thus, in the financial module DBR equals 2.0 in 1980 and 1.5 thereafter. The 1982 tax law changes also require that the original tax depreciation basis for assets placed in service after 1982 be reduced by 50 percent of the amount of the investment tax credit earned by the asset. Alternatively, the investment tax credit rate may be reduced by two percentage points. The first option is more advantageous in present value terms and is therefore the alternative used in the module.

Conveniently, the code now provides depreciation rate schedules for each new asset life: fractions for each year that can be multiplied by the original value of the asset to get that year's tax depreciation. The model makes use of two sets of schedules, one for 10-year tax lives and one for 15-year tax lives. It avoids a number of complicated computations by obtaining these rates as data, choosing the appropriate set, assigning its values to the array DRATE, and passing them to the depreciation subroutine so that

$$TXDP_t = DPRATE_t * CCO. \tag{17}$$

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[3] The sum of the years' digits method of accelerated depreciation applies a changing fraction each year to the original basis of the asset. The denominator of the fraction is the sum of the numbers that represent each year of the life of the asset (i.e., if the life equals n, the denominator equals 1 + 2 + ... + n-1 + n); the numerator each year is the number of years of remaining useful life.

If the plant's starting date is later than 1982, TCADJ, equal to half of the investment tax credit earned by the plant, is subtracted from CCO.

3.2.1.6 **Investment Tax Credit.** The investment tax credit (itc) is another major tax benefit available to corporations. It amounts to 10 percent of eligible investment in plant and equipment. An additional amount may be claimed for a corporation's employee stock ownership plan (ESOP): before 1983 it was 1 percent of eligible investment plus an additional 0.5 percent if employees contributed a matching amount to the plan. Now the extra 1.5 percent will be based on compensation paid to employees under the plan and is scheduled to terminate entirely after 1986.

The model ignores the employment-based addition to the tax credit (which would be very small for electric utilities). Thus, the investment tax credit rate, ZITCR, equals 11.5 percent until 1982 and 10 percent thereafter. Ninety percent of the investment cost of an electric generating facility is assumed to be eligible for the credit. Eligibility of pollution control equipment retrofitted to older plants is complex and is discussed below.

3.2.1.7 **Pollution Control Equipment: Tax Depreciation and Credits.** Pollution control equipment built with new plants can be depreciated as part of the utility plant under whatever approved system the utility uses for tax purposes.

Depreciation rules available for certain retrofitted pollution control devices are more complex.[4] If the device is for a generating facility in existence before January 1, 1976, the utility may depreciate it on a straight-line basis over 60 months, beginning as early as the month following acquisition or installation of the device. Two conditions determine the depreciable basis of the equipment:

1. If its useful life exceeds 15 years, then the portion of costs eligible for the rapid five-year amortization equals 15/L, where L is the actual useful life. The remaining fraction is amortized over the full life.

2. If the useful life is 15 years or less, then the full cost of the equipment is eligible for 60-month amortization.

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[4] This discussion is based on Reference 11.

Since the model assumes a 20-year operating life for pollution control devices, it computes straight-line depreciation over five years for three quarters (15/20) of a retrofitted asset's value and straight-line over 20 years for the remaining one quarter.

The eligibility of pollution control equipment for the investment tax credit depends first on whether the equipment investment is financed by tax-exempt bonds. If not, the following rules apply:

1. For equipment in service before 1977, no itc is allowed on the portion of costs that is eligible for the 60-month rapid amortization.

2. For equipment added in 1977 or 1978 on utility plant in service before 1976, a maximum of 50 percent of the rapid amortization basis is eligible for the itc.

3. For devices acquired or constructed after 1978 for utility plant in service before 1976, 100 percent of the value of the asset is eligible for the itc provided the equipment has at least a five-year useful life (if less than five years, one-third is eligible).

If the equipment is financed by tax-free bonds, more complex rules apply which in effect allow a lower eligibility for the itc even on devices installed after 1978. Since retrofitted devices in the model will be installed after 1978, have 20-year lives, and are assumed not to be financed by tax-exempt bonds, 100 percent of their construction cost (exclusive of afudc) is assumed eligible for the itc.

3.2.1.8 **Actual Corporate Tax Paid.** Thus, the actual federal corporate income tax paid by a utility would be computed as

$$FTI_t = OPREVE_t - SUMM_t - SITX_t - TXDEPR_t - LTDEXP_t \tag{18}$$

$$FITX_t = FTI_t * FTXR - ITC_t \tag{19}$$

where FTI is taxable income, OPREVE is operating revenues actually received, SUMM is business and operating expenses as noted above, SITX is state corporate income tax paid,[5] TXDEPR is the depreciation deduction defined above (TXDP aggregated over all assets), LTDEXP is interest paid, FTXR is the federal corporate income tax rate, and ITC is the investment tax credit.

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[5] The state corporate income tax computation is identical to that for the federal tax except that state income tax is not a deduction, the tax rate is different, and there is no investment credit.

The current federal income tax report is shown in Table 3-3.

3.2.1.9 **Tax Accounting Options and Adjusted Rate Base.** Regulatory commissions, however, may assume different values for the components of the tax allowance equations TF and TS than those used by the utility in computing its actual tax. Specifically, regulatory treatment of the tax benefits of accelerated depreciation and the investment tax credit may differ in two ways from their actual incidence on the utility. First, in setting rates, a commission may ignore all or part of certain tax benefits that accrue to the utility so that required revenues (and thus rates) are higher than if all these benefits were recognized. Second, a commission may recognize tax benefits for rate-making during a period other than that in which they were earned by the utility by using normalized rather than flow-through accounting.

Flow-through accounting passes tax savings on to customers in the year they were earned by the utility so that in the tax allowance equation,

$$TF_t = ((RC_t + RP_t + RBDP_t - REGDPE_t) * \frac{FTXR}{1-FTXR}) , \qquad (20)$$

REGDPE is equal to TXDEPR. In addition, flow-through accounting further reduces TF by (ITC * $\frac{1}{1-FTXR}$), the full amount of the investment tax credit.

In normalized accounting, REGDPE differs from TXDEPR and the investment tax credit factor is not subtracted from TF. Therefore, the tax allowance that enters into revenue requirement for that year may be lower or higher than the utility's actual tax expense. However, the difference between the tax allowance calculated by the commission and the actual tax expense is credited to a reserve that is subtracted from the utility's rate base. In effect, the utility is allowed the immediate use of these tax savings. However, since they are essentially monies contributed by ratepayers, deducting them from the rate base precludes the utility from earning a return on them and returns them to the customer over time.

The present version of the module allows three different tax accounting options: flow-through, full normalization, and partial normalization. The flow-through option was described above.

TABLE 3-3

AUSM FEDERAL INCOME TAX, CURRENT

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SCENARIO:        *** AUSM ***             *** AUSM ***                          OCTOBER  (:::::::::)
                 *** AUSM ***         STATE LEVEL MODEL-SINGLE STATE            *** AUSM ***

AUSM REPORT - 602: FINANCIAL SUMMARY


 NORTH CAROLINA    (37)


FEDERAL INCOME TAX, CURRENT    (ALL VALUES IN MILLIONS OF CURRENT DOLLARS)

                  1980     1981     1982     1983     1984     1985     1986     1987     1988     1989

TAXABLE INCOME
 TOT OPER REV    2267.    2559.    2968.    3316.    3575.    3730.    4012.    4600.    4836.    4879.
 (DIR OP EXPS)   1576.    1915.    1881.    2152.    2202.    2584.    3028.    3137.    3343.    3513.
 (ACCEL DEPR)     228.     263.     436.     739.     852.     856.     794.    1059.    1139.    1074.
 (GR REC TAX)      17.      19.      22.      25.      27.      28.      30.      34.      36.      37.
 (PROP TAX)        92.     100.     145.     198.     203.     215.     207.     272.     266.     259.
 (ST INC TAX).      1.      -9.       3.     -15.      -9.     -25.     -29.     -26.     -25.     -27.
 (OTHER TAXES)     23.      26.      30.      33.      36.      37.      40.      46.      48.      49.
 (INTERST EXP)    316.     387.     395.     416.     405.     421.     399.     479.     428.     395.
        TOTAL      15.    -142.      55.    -232.    -141.    -387.    -458.    -403.    -399.    -420.

 (INV TX CRED)     94.      77.      74.      48.      77.      22.     144.       0.       0.       0.

 TOTAL TAX PD     -88.    -142.     -49.    -154.    -142.    -200.    -355.    -161.    -136.    -143.
```

In the full normalization option, the tax allowance equation uses a depreciation deduction that reflects neither a shorter tax life nor an accelerated rate: REGDPE is straight-line depreciation of the tax basis of an asset (direct investment cost exclusive of afudc) over its book life. In addition, TF is not reduced by (ITC $* \frac{1}{1-FTXR}$), the investment tax credit. Thus the utility is allowed immediate use of the full value of these tax savings, but these savings are accumulated in separate accounts and are subtracted from the rate base over the life of each asset. The account for deferred tax savings from accelerated depreciation is

$$ADFRGE_t = ADFRGE_{t-1} + (TXDEPR_t - REGDPE_t) * ETXR \, . \qquad (21)$$

The account for the investment tax credit adjustment (ACITC) is derived by computing for each asset

$$TOTITC_t - (AITC * t) \qquad (22)$$

and summing these values over all assets for each year. ($TOTITC_1$ equals the total amount of investment tax credit attributable to that asset, AITC equals ($TOTITC_1$/operating life), and t = 1, ..., operating life.) Thus in full normalization

$$ADJRBS_t = GRSSRB_t - ADPRBE_t - ADFRGE_t - ACITC_t \qquad (23)$$

where the last two terms reflect the full value of these tax savings.

In the partial normalization option the commission normalizes part and flows through the remaining part of the tax savings from accelerated depreciation. It also normalizes part of the investment tax credit but allows the utility to retain the rest permanently. In this option, which is used in New York and some other states, REGDPE is computed with the accelerated depreciation rate (twice the straight-line rate) but using the book life (LIFN) rather than the shorter tax life of the assets. Thus,

$$REGDPE_t = (DBR_t / LIFN) * DB2_t * CCO. \qquad (24)$$

This should be compared with Equation 16 for TXDP. ADFRGE is computed as above but with this different value of REGDPE so that, in effect, the tax savings due to the accelerated rates are flowed through.

Because the 1981 and 1982 tax law provisions for depreciation may be used only if the tax savings are fully normalized, the partial normalization option partially normalizes depreciation for historical plant but fully normalizes depreciation for new plant. It uses partial normalization of the ITC for all assets.

As in full normalization, $(\mathrm{ITC} * \frac{1}{1-FTXR})$ is not subtracted from TF. However, only a fraction of ACITC (.08/ZITCR, where ZITCR equals the investment tax credit rate of 0.10 to 0.115) is deducted from the rate base; the remainder is retained by the utility. As in full normalization, adjusted rate base, ADJRBS_t equals GRSSRB_t - ADPRBE_t - ADFRGE_t - ACITC_t, but the last term does not represent the full value of the tax savings earned from the investment tax credit. Also, for historical plant, the deferred tax account ADFRGE reflects only those tax savings due to shorter tax lives, the rest having been flowed through to consumers.

In fact, ADJRBS in the flow-through case is defined by the same Equation 23, but the last two terms equal zero because the tax benefits were flowed through to customers in the year received. Consequently, there is no subsequent rate base adjustment for these two terms.

This discussion has mentioned several ways in which utilities and regulatory commissions can affect the size of revenue requirement and thus the rates that the company will be allowed to charge. The commission controls the size of revenue requirement principally by determining the rate of return allowed on common equity, by allowing or disallowing cwip in the rate base, and by normalizing or flowing through the company's corporate income tax savings. The company affects the magnitude of the capital portion of the revenue requirement mainly by its investment in new plants and their ultimate construction cost.

The value that determines the financial health of the company is, finally, not the revenue it is allowed to earn but the revenue it actually earns. If demand is sufficiently elastic, the higher rates caused by a large construction program may reduce the revenue received rather than increase it, or result in revenues that are less than expected. This will make it more difficult for the utility to finance its ongoing projects.

To allow for such possibilities, the AUSM demand module structures REVRQ into a rate schedule. It then determines the next year's demand for electricity and actual revenue earned from electricity sales. The latter variable is an important input to the second financial subroutine, R602.

3.2.2 R602 and the Financial Reports

The second financial subroutine, R602, is a part of AUSMR. It computes the standard financial statements and ratios and prints the reports shown in this section.

3.2.2.1 **The Income Statement.** The computing of income statement items begins with interest expense, which is based on long-term debt as of January 1. Short-term debt is usually small relative to long-term debt, and it is not included in the model.

Computing interest on January 1 debt before new debt is issued or any debt is retired is unrealistic. Some new debt (that issued in the first half of the year) may add to that year's interest expense, since interest is often paid every six months on long-term bonds. On the other hand, a full year's interest would not be due on all of the long-term debt retired that year. To some extent these effects will cancel, although accelerating inflation will give greater weight to the new-issue effect, and so interest expense may be somewhat underestimated in such periods. Nevertheless, this assumption greatly simplifies the model and in particular avoids recomputations to balance certain of the financial statements.

Average actual interest rates have been calculated for each state for the base year 1980. The user-specified new interest rate is used with the initial rates to calculate an embedded interest rate for each state for each year. This "embedded" rate is the average over both old and new debt. An identical method calculates "embedded" average rates of return on preferred equity for each state, and this too is annual.

Having completed the interest expense determination, the program then calculates actual federal and state income tax paid (see Equations 18 and 19). The components of this calculation comprise one of the tables printed in the report entitled "Federal Income Tax, Current" (Table 3-3).

Net income in Table 3-4 is

$$NETINC_t = OPREVE_t - EXPTOT_t + OTHINC_t - TOTINT_t . \qquad (25)$$

$OPREVE_t$ is the actual revenue from electric sales passed from the demand subroutine. Total operating expenses EXPTOT are defined by

TABLE 3-4

AUSM INCOME STATEMENT

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SCENARIO:        *** AUSM ***          *** AUSM ***                            OCTOBER  (::::::::)
                 *** AUSM ***       STATE LEVEL MODEL-SINGLE STATE             *** AUSM ***

AUSM REPORT - 602: FINANCIAL SUMMARY


 NORTH CAROLINA     (37)


INCOME STATEMENT    (ALL VALUES IN MILLIONS OF CURRENT DOLLARS)

                    1980     1981     1982     1983     1984     1985     1986     1987     1988     1989

ELEC OPER REV      2267.    2559.    2968.    3316.    3575.    3730.    4012.    4600.    4836.    4879.

DIR ELEC OP EXP:
 PURCH POWER       -161.      44.    -125.     116.    -126.     272.    -281.    -358.    -349.    -348.
 FUEL,COAL          811.     872.     860.     796.     935.     890.    1363.    1349.    1419.    1470.
 FUEL,NUCLEAR        67.      72.     134.     204.     218.     233.     247.     316.     323.     324.
 FUEL,DIST OIL       36.      37.      24.       9.       9.      10.      43.      43.      42.      40.
 FUEL,RES. OIL        0.       0.       0.       0.       0.       0.       0.       0.       0.       0.
 FUEL,NAT. GAS       63.      75.      88.      63.      72.      83.     147.     152.     145.     126.
 FUEL,OTHER           0.       0.       0.       0.       0.       0.       0.       0.       0.       0.
 ADMIN,CUST         404.     433.     474.     502.     571.     572.     790.     852.     919.     992.
 PLANT MAINT        158.     169.     195.     215.     243.     244.     329.     364.     392.     421.
 P. C. MAINT         16.      17.      17.      18.      21.      21.      32.      33.      35.      37.
 OTHER MAINT        183.     197.     215.     228.     259.     260.     358.     386.     417.     450.
DEPRECIATION        204.     222.     253.     314.     332.     359.     359.     456.     459.     463.

OPER TAX EXP:
 INC TAX PAID       -87.    -151.     -46.    -169.    -151.    -225.    -384.    -187.    -161.    -170.
 INC TAX DEF         31.      41.     104.     215.     247.     238.     207.     307.     330.     296.
 INC TAX CRED        94.      77.      74.      48.      77.      22.     144.       0.       0.       0.
 LESS TAX ADJ        11.      12.      15.      21.      22.      25.      25.      34.      34.      34.
   INC TX REP        29.     -45.     118.      72.     151.      10.     -57.      87.     135.      92.
 GROSS REC TAX       17.      19.      22.      25.      27.      28.      30.      34.      36.      37.
 PROPERTY TAX        92.     100.     145.     198.     203.     215.     207.     272.     266.     259.
 SOC SEC,OTHER       23.      26.      30.      33.      36.      37.      40.      46.      48.      49.
TOTAL OPER EXP     1941.    2237.    2449.    2794.    2951.    3234.    3607.    4033.    4288.    4413.

AFUDC-EQUITY          0.       0.       0.       0.       0.       0.       0.       0.       0.       0.
TOT OTHER INC         0.       0.       0.       0.       0.       0.       0.       0.       0.       0.

L TERM INT EXP      316.     387.     395.     416.     405.     421.     399.     479.     428.     395.
(AFUDC-DEBT)          0.       0.       0.       0.       0.       0.       0.       0.       0.       0.
TOTAL INT EXP       316.     387.     395.     416.     405.     421.     399.     479.     428.     395.

NET INCOME           10.     -65.     123.     106.     219.      75.       6.      88.     121.      72.
```

$$EXPTOT_t = DNORME_t + GRTX_t + SSOTX_t + PTX_t + ITXR_t + DOEXP_t + OPEXPO_t \tag{26}$$

where DNORME is the annual straight-line depreciation of gross electric plant; GRTX is the gross receipts tax; SSOTX is social security and other taxes, a fixed percentage of OPREVE; and property tax, PTX, is a fixed percentage of TBASE. OPEXPO, other operating expenses, equals total sales times a fixed cost in mills per kilowatt hour, adjusted for inflation. ITXR is reported income tax, which equals actual state and federal corporate tax paid plus that year's tax savings from accelerated depreciation[6] and the tax savings from the investment credit, reduced by the year's amortization of accumulated credits:

$$ITXR_t = ITXP_t + DFTXBK_t + ITC_t - TCTKN_t. \tag{27}$$

This last adjustment spreads the value of the credit over the asset's life, for book purposes. Direct operating expense, DOEXP, equals the sum of purchased power, fuel, and operation and maintenance expenses. Other income, OTHINC, consists of the equity portion of afudc. TOTINT is equal to LTDEXP, the interest expense on long-term debt, minus the debt portion of afudc. Thus, both afudc components augment net income.

Retained earnings are seen in the report in Table 3-5. At the end of the year, they equal their earlier January 1 value for the year plus net income, and minus preferred and common stock dividends. Preferred stock dividends are computed by multiplying the rate of return on preferred stock by the amount of preferred equity at the beginning of the year. Common stock dividends are 15 percent of January 1 retained earnings but equal zero if net income minus preferred dividends is not greater than zero [12].

Once retained earnings are determined, the model can compute the amount of external funds (FNEEDS) the utility needs to raise that year:

$$\begin{aligned} FNEEDS_t = {} & GRSSPE_t - ADRPBE_t + CWIPE_t + ACCTR_t + OTHASS_t \\ & - (CEQTOT_{t-1} + PEQTOT_{t-1} + LTDTOT_{t-1} - DRETIR_t \\ & + LIACAO_t + ACTCT_t + ADFBK_t + RETERN_t). \end{aligned} \tag{28}$$

---

[6] Whatever method of tax accounting the state uses for regulation, deferred taxes in the standard financial statements equal the tax rate times the difference between tax depreciation (accelerated rate and shorter life) and straight-line depreciation (operating life).

TABLE 3-5

AUSM RETAINED EARNINGS

```
SCENARIO:          *** AUSM ***              *** AUSM ***                          OCTOBER  (::::::::)
                   *** AUSM ***         STATE LEVEL MODEL-SINGLE STATE             *** AUSM ***

AUSM REPORT - 602: FINANCIAL SUMMARY


 NORTH CAROLINA    (37)

RETAINED EARNINGS     (ALL VALUES IN MILLIONS OF CURRENT DOLLARS)

                   1980      1981      1982      1983      1984      1985      1986      1987      1988      1989

 JANUARY 1 BAL     568.      496.      334.      358.      350.      470.      417.      329.      272.      272.

 NET INCOME         10.      -65.      123.      106.      219.       75.        6.       88.      121.       72.
 (PREF DIVIDS)      81.       98.       99.      104.       99.       99.       94.      114.       96.       84.
 (COM DIVIDS)        0.        0.        0.       10.        0.       28.        0.       30.       25.       19.

DECEMBR 31 BAL     496.      334.      358.      350.      470.      417.      329.      272.      272.      241.
```

Essentially, the amount of external funds is chosen to equate assets and liabilities on the balance sheet. Assets are GRSSPE minus its accumulated book depreciation, the exogenous other assets (OTHASS), accounts receivable (ACCTR), and construction work in progress (CWIPE). On the liabilities side are the January 1 values of debt and equity ($CEQTOT_{t-1}$, $PEQTOT_{t-1}$, and $LTDTOT_{t-1}$) less debt to be retired that year (DRETIR), accumulated deferred taxes and investment credits (ACTCT and ADFBK), current and other liabilities (LIACAO), and retained earnings (RETERN).

If FNEEDS is less than zero, i.e., the utility has excess funds, the model retires debt and reduces the equity balances. It does so by buying back common and preferred stock and increasing common dividends so as to retain the exogenous percentages of debt and equity in the capital structure. The desired levels of each are

$$DDEBT_t = DTPC * (CAPTOT_{t-1} - DRETIR_t + FNEEDS_t), \tag{29}$$

$$DPEQ_t = PEQPC * (CAPTOT_{t-1} - DRETIR_t + FNEEDS_t), \tag{30}$$

$$DCEQ_t = CEQPC * (CAPTOT_{t-1} - DRETIR_t + FNEEDS_t), \tag{31}$$

$$CAPTOT_{t-1} = COMTOT_{t-1} + LTDTOT_{t-1} + PEQTOT_{t-1}, \tag{32}$$

where CAPTOT is total capitalization and COMTOT is common equity including retained earnings ($RETERN_t$).

If the desired level of debt is greater than its current level ($LTDTOT_{t-1}$ - $DRETIR_t$) due to normal retirements, excess funds are used entirely to adjust equity, and the above calculations are altered accordingly.

The desired level of common equity is achieved partly by reducing retained earnings (increasing dividends), according to retained earnings' current share of total common equity (RETPCT):

$$CDIV_t = CDIV_t + RETPCT * (CEQTOT_{t-1} + RETERN_t - DCEQ_t). \tag{33}$$

Thus, new common equity (the negative value of stock purchases) is

$$NWCEQ_t = -(1 - RETPCT) * (CEQTOT_{t-1} + RETERN_t - DECQ_t). \tag{34}$$

Retained earnings ($RETERN_t$) are then adjusted to reflect the new level of CDIV. New preferred equity (the negative value of stock purchased) is simply:

$$NWPEQ_t = -(PEQTOT_{t-1} - PDEQ_t). \tag{35}$$

Additional debt retirements are:

$$DEBTCH_t = LTDTOT_{t-1} - DRETIR_t - DDEBT_t. \tag{36}$$

If FNEEDS is greater than zero, external funds must be raised. The object again is to retain the state's base-year capitalization ratios. For example, the amount of new debt issued is:

$$\begin{aligned} NWDT_t = {} & DTPC * (CAPTOT_{t-1} - DRETIR_t + FNEEDS_t) \\ & - (LTDTOT_{t-1} - DRETIR_t). \end{aligned} \tag{37}$$

In the model, if NWDT as computed by Equation 37 is greater than or equal to FNEEDS, then NWDT = FNEEDS and no new stock is issued that year.

The debt issued is assumed to be 20-year bonds with a yearly coupon and the principal due at the end of the term. The model, therefore, augments the debt retirement account (DRETIR) 20 years hence:

$$DRETIR_{t+20} = NWDT_t + DRETIR_{t+20}. \tag{38}$$

The first financial subroutine has already initialized DRETIR with a retirement schedule for debt outstanding before the first simulation year. Because disaggregated data on outstanding debt issues are not readily available, this schedule for historical debt repays principal as it would be repaid on a mortgage.

The model then computes new preferred and common equity issues:

$$\begin{aligned} NWCEQ_t = {} & CEQPC * (CAPTOT_{t-1} - DRETIR_t + FNEEDS_t) \\ & (CEQTOT_{t-1} + RETERN_t), \text{ and} \end{aligned} \tag{39}$$

$$\begin{aligned} NWPEQ_t = {} & PEQPC * (CAPTOT_{t-1} - DRETIR_t + FNEEDS_t) - \\ & PEQTOT_{t-1}. \end{aligned} \tag{40}$$

Finally, total values for debt and equity are computed for the balance sheet. First old values and then the total are computed:

$$\mathrm{OLDT}_t = \mathrm{LTDTOT}_{t-1} - \mathrm{DRETIR}_t, \tag{41}$$

$$\mathrm{OLDPEQ}_t = \mathrm{PEQTOT}_{t-1}, \tag{42}$$

$$\mathrm{OLDCEQ}_t = \mathrm{CEQTOT}_{t-1}, \tag{43}$$

$$\mathrm{LTDTOT}_t = \mathrm{OLDT}_t + \mathrm{NWDT}_t, \tag{44}$$

$$\mathrm{PEQTOT}_t = \mathrm{OLDPEQ}_t + \mathrm{NWPEQ}_t, \tag{45}$$

$$\mathrm{CEQTOT}_t = \mathrm{OLDCEQ}_t + \mathrm{NEWCQ}_t. \tag{46}$$

Note that CEQTOT includes only stock issued, not the value of retained earnings.

3.2.2.2 The Balance Sheet. The balance sheet report appears in Table 3.6. New electric plant, which equals gross plant (GRSSPE) minus accumulated straight-line depreciation (ADPRBE), is added to construction work in progress (CWIPE) to define total electric plant. CASH plus the exogenous ACCTR (accounts receivable) equals current and other assets (ASSCAO). On the liabilities side, prior common equity (COMTOT). Preferred equity is broken down into new and prior issues (NWPEQ and OLDPEQ). Long-term debt (LTDTOT), accumulated deferred taxes from depreciation (ADFBK), and the accumulated investment tax credit (ACTCT) complete the liabilities side. If total assets and total liabilities are not equal, the difference (CORR) is added to total liabilities as a correction in the first year.

The program then calculates working capital as the difference between current assets and current liabilities:

$$\mathrm{WCAP}_t = \mathrm{ASSCAO}_t - \mathrm{LIACAO}_t. \tag{47}$$

3.2.2.3 Cash Flow. The funds flow statement items are essentially changes in the balance sheet components from one year to the next. Table 3-7 shows that funds provided are:

$$\begin{aligned}\mathrm{FDPROV}_t = {} & \mathrm{NETINC}_t + \mathrm{DNORME}_t - \mathrm{AFUDCE}_t - \mathrm{AFUDCD}_t \\ & + \mathrm{NWDT}_t + \mathrm{NWCEQ}_t + \mathrm{NWPEQ}_t + \mathrm{CHAITC}_t.\end{aligned} \tag{48}$$

That is, funds provided equal net income plus normal depreciation, deferred taxes, the change in ACTCT from the previous year, and new issues of debt and equity, minus the noncash afudc items. Funds applied are:

$$\begin{aligned}\mathrm{FDAPPL}_t = {} & \mathrm{ADDE}_t + \mathrm{ADDP}_t - \mathrm{AFUDCE}_t - \mathrm{AFUDCD}_t + \mathrm{DRETIR}_t \\ & + \mathrm{PDIV}_t + \mathrm{CDIV}_t + \mathrm{CHWCAP}_t\end{aligned} \tag{49}$$

TABLE 3-6

AUSM BALANCE SHEET

```
SCENARIO:        *** AUSM ***           *** AUSM ***                            OCTOBER  (::::::::)
                 *** AUSM ***       STATE LEVEL MODEL-SINGLE STATE              *** AUSM ***

AUSM REPORT - 602: FINANCIAL SUMMARY

 NORTH CAROLINA    (37)

BALANCE SHEET    (ALL VALUES IN MILLIONS OF CURRENT DOLLARS)

                   1980      1981      1982      1983      1984      1985      1986      1987      1988      1989
ASSETS:

 ELEC UTIL PLT    7156.     7785.     8820.    10842.    11471.    12497.    12497.    15900.    16064.    16241.
 (ACCUM DEPR)     2045.     2285.     2558.     2893.     3243.     3629.     3988.     4477.     4940.     5407.
 NET ELEC PLT     5112.     5500.     6262.     7949.     8228.     8868.     8509.    11424.    11124.    10834.
 CWIP             4057.     4171.     3854.     2361.     2586.     1802.     3403.      164.      177.      196.
   TOT ELEC PL    9169.     9671.    10116.    10310.    10814.    10670.    11912.    11587.    11301.    11030.

 CURR. ASSETS      552.      586.      621.      658.      697.      739.      784.      831.      880.      933.

 TOTAL ASSETS     9721.    10256.    10737.    10968.    11511.    11409.    12696.    12418.    12182.    11963.

TOTAL CAPITALIZATION, LIABILITIES, CREDITS:

 PRIOR COM EQ     2037.     2289.     2649.     2710.     2637.     2637.     2471.     2940.     2646.     2424.
 NEW COM EQ        252.      360.       61.      -73.        0.     -166.      469.     -294.     -222.     -174.
 RETAINED EARN     496.      334.      358.      350.      470.      417.      329.      272.      272.      241.
   TOT COM EQ     2785.     2983.     3068.     2987.     3106.     2888.     3268.     2918.     2696.     2490.

 PRIOR PREF EQ     967.     1081.     1092.     1123.     1094.     1094.     1057.     1197.     1068.      987.
 NEW PREF EQ       114.       11.       31.      -30.        0.      -36.      139.     -128.      -81.      -75.
   TOT PREF EQ    1081.     1092.     1123.     1094.     1094.     1057.     1197.     1068.      987.      912.

 LONG TERM DT     4042.     4075.     4191.     4081.     4165.     3945.     4465.     3986.     3683.     3402.

 CURR LIABILS      793.      840.      890.      944.     1001.     1061.     1124.     1192.     1263.     1339.

 ACCUM DEF ITC     316.      360.      442.      614.      640.      699.      674.      952.      918.      884.

 AC DEF INC TX     856.      907.     1022.     1249.     1506.     1760.     1967.     2302.     2634.     2936.

   TOT LIABILS    9721.    10256.    10737.    10968.    11511.    11409.    12696.    12418.    12181.    11963.
```

TABLE 3-7

AUSM FUNDS PROVIDED AND APPLIED

```
SCENARIO:          *** AUSM ***          *** AUSM ***                          OCTOBER  (::::::::)
                   *** AUSM ***        STATE LEVEL MODEL-SINGLE STATE          *** AUSM ***

AUSM REPORT - 602: FINANCIAL SUMMARY


 NORTH CAROLINA    (37)


FUNDS PROVIDED AND APPLIED    (ALL VALUES IN MILLIONS OF CURRENT DOLLARS)

                  1980     1981     1982     1983     1984     1985     1986     1987     1988     1989

FUNDS PROVIDED
 NET INCOME        10.     -65.     123.     106.     219.      75.       6.      88.     121.      72.
 DEPRECIATION     204.     222.     253.     314.     332.     359.     359.     456.     459.     463.
 DEFERRED TAX      31.      41.     104.     215.     247.     238.     207.     307.     330.     296.
 DEFERRED ITC       0.      44.      83.     171.      26.      59.     -25.     277.     -34.     -34.
 LESS
   AFUDC-EQ         0.       0.       0.       0.       0.       0.       0.       0.       0.       0.
   AFUDC-DEBT       0.       0.       0.       0.       0.       0.       0.       0.       0.       0.
 NEW LT DEBT      494.     113.     203.       0.     187.       0.     642.       0.       0.       0.
 NEW COM STOCK    252.     360.      61.     -73.       0.    -166.     469.    -294.    -222.    -174.
 NEW PREF STCK    114.      11.      31.     -30.       0.     -36.     139.    -128.     -81.     -75.
 OTHER,MISC       416.     179.      30.      34.      27.      43.       0.      60.       7.      10.
  TOT FDS PROV   1522.     905.     889.     737.    1040.     571.    1798.     766.     580.     557.

FUNDS APPLIED:
 ADDNS,UTIL PL   1380.     742.     718.     529.     854.     242.    1601.     164.     177.     196.
 ADDNS,POL CON      0.       0.       0.       0.       0.       0.       0.       0.       0.       0.
 LESS
   AFUDC EQ         0.       0.       0.       0.       0.       0.       0.       0.       0.       0.
   AFUDC DEBT       0.       0.       0.       0.       0.       0.       0.       0.       0.       0.
 DEBT RETIREMENT   60.      80.      87.     111.     103.     220.     122.     479.     303.     281.
 PREF STK DIVS     81.      98.      99.     104.      99.      99.      94.     114.      96.      84.
 COM STK DIVS       0.       0.       0.      10.       0.      28.       0.      30.      25.      19.
 CHG,WORK CAP       0.     -14.     -15.     -16.     -17.     -18.     -19.     -20.     -22.     -23.
  TOT FDS APPL   1522.     905.     889.     737.    1040.     571.    1798.     766.     580.     557.
```

where ADDE and ADDP are the yearly construction costs including afudc, for generation facilities and pollution control equipment, and $CHWCAP_t$ equals $WCAP_t$ - $WCAP_{t-1}$. SOURCO, other sources of funds, balances the statement, that is,

$$SOURCO_t = FDAPPL_t - FDPROV_t \tag{50}$$

$$FDPROV_t = FDPROV_t + SOURCO_t. \tag{51}$$

The base year value of SOURCO, in Table 3-7, for example, is small. Its second-year value echoes the first-year correction in the balance sheet, since CORR is not incorporated into any of that statement's subentries but only into total liabilities.

3.2.2.4 Summary Financial Statistics. Finally, R602 computes two sets of ratios that provide measures of a utility's financial health to its debtors and equity holders: interest coverage and profitability ratios. (These are shown in Table 3-8, another report from a full AUSM run.) Electric Utilities have a variety of noncash items in their income statements, all of which may be large in magnitude because of their capital intensity, especially for companies with construction programs: afudc augments net income, book depreciation decreases it, and deferred taxes from accelerated depreciation decrease it, although the latter are temporarily available for use to utilities with normalized accounting. A useful measure of earnings for these ratios must take account of these factors, and so the model computes several alternative measures.

The interest coverage ratio measures the number of times earnings will cover interest expense. The denominator is therefore

$$DEN1_t = LTDEXP_t, \tag{52}$$

the year's interest expense for long-term debt. The first measure,

$$COV1_t = (OPREVE_t - EXPTOT_t) / DEN1_t, \tag{53}$$

TABLE 3-8

AUSM INTEREST COVERAGE AND PROFITABILITY RATIOS

```
SCENARIO:          *** AUSM ***              *** AUSM ***                                      OCTOBER  (::::::::)
                   *** AUSM ***          STATE LEVEL MODEL-SINGLE STATE                        *** AUSM ***

AUSM REPORT - 602: FINANCIAL SUMMARY


 NORTH CAROLINA    (37)


INTEREST COVERAGE AND PROFITABILITY RATIOS

INTEREST COVERAGE RATIOS

                     1980      1981      1982      1983      1984      1985      1986      1987      1988      1989

OPER INCOME          1.032     0.832     1.312     1.254     1.540     1.178     1.014     1.184     1.283     1.181
OP INC+INC TX        1.123     0.715     1.610     1.426     1.913     1.202     0.871     1.365     1.598     1.415
OPER INCOME +
 INC TX&DEPREC       1.770     1.289     2.250     2.181     2.732     2.055     1.771     2.317     2.673     2.588
INC BEFORE INT       1.032     0.832     1.312     1.254     1.540     1.178     1.014     1.184     1.283     1.181


PROFITABILITY RATIOS
NET INCOME
 DIV BY EQUITY       0.003    -0.016     0.029     0.026     0.052     0.019     0.001     0.022     0.033     0.021
ADJ NET INCOME
 DIV BY EQUITY       0.011    -0.006     0.054     0.078     0.111     0.079     0.048     0.099     0.122     0.108
PRE INT NET INC
  DIV BY RBASE       0.064     0.059     0.083     0.066     0.076     0.056     0.048     0.050     0.049     0.043
ADJ PRE INT NET INC
  DIV BY RBASE       0.070     0.066     0.099     0.093     0.106     0.083     0.072     0.077     0.079     0.070
```

excludes afudc from earnings but does not take account of the availability of funds from depreciation and deferred taxes. The second ratio, based on pretax operating income, is

$$COV2_t = (OPREVE_t - EXPTOT_t + ITXR_t)/DEN1_t. \tag{54}$$

It therefore accounts for the availability of deferred taxes and the investment tax credit. The third measure, based on pretax cash flow, includes funds from depreciation:

$$COV3_t = (OPREVE_t - EXPTOT_t + ITXR_t + DNORME_t)/DEN1_t. \tag{55}$$

These three measures allow one to see the effects of each noncash item on the interest coverage ratio. The final measure is a more standard one, based on net income before interest payments:

$$COV4_t = (OPREVE_t - EXPTOT_t + OTHINC_t)/DEN1_t. \tag{56}$$

It includes, as part of earnings, the equity portion of afudc and does not take account of funds from depreciation.

The profitability measures show the earnings available for stockholders normalized to the size of the firms involved. One logical denominator would seem to be total equity, the stockholders' contribution, and two measures are computed with the denominator

$$DEN2_t = COMTOT_t + PEQTOT_t. \tag{57}$$

The first is based simply on net income:

$$PROF1_t = NETINC_t/DEN2_t. \tag{58}$$

Because of the importance of noncash items in utilities' income statements, a second measure accounts for the largest of these by excluding afudc and adding back deferred taxes:

$$PROF2_t = (NETINC_t - AFUDCD_t - AFUDCE_t + DFTXBK_t)/DEN2_t. \tag{59}$$

Under some circumstances, however, the denominator DEN2 may provide misleading measures of profitability because it includes retained earnings. For example, over a period of declining profitability, retained earnings and therefore DEN2 will increase more slowly or may even decline, so that PROF1 or PROF2 may overstate the company's profitability. The model therefore computes two more profitability measures with net plant in the denominator:

$$DEN3_t = NETPE_t = GRSSPE_t - ADPRBE_t. \qquad (60)$$

These measures are of overall returns to both debt and equity holders. The first is pre-interest net income (including both afudc items):

$$PROF3_t = (NETINC_t + TOTINT_t + AFUDCD_t)/DEN3_t. \qquad (61)$$

The final measure excludes the debt and equity portions of AFUDC from earnings and accounts for funds from deferred taxes:

$$PROF_t = (NETINC_t + TOTINT_t - AFUDCE - AFUDCD_t + DFTXBK_t)/DEN3_t. \qquad (62)$$

The importance of the noncash items is evident in the financial summary, where versions of interest coverage and profitability ratios may differ in sign as well as in magnitude.

In addition to printing the standard financial reports (income statement, statement of retained earnings, balance sheet, and funds flow) and the coverage and profitability ratios, the R602 subroutine also prints the tables showing the components of required revenue and items in the federal corporate income tax calculation discussed in Section 3.2.1.8.

3.3 Data

The exogenous data required for the AUSM financial module are of two types: numerical and logical. The data were collected earlier as part of an extensive review of state regulatory practices [4]. Tables 3-9, 3-10, and 3-11 are excerpted from that review.

As shown in the Table 3-9 excerpt, for example, almost all states used full normalization of tax benefits for the investment tax credit. However, the four states that flowed-through part of the credit included California and New York. The financial module, as explained above, is written to permit full or partial normalization or flow-through regulation according to the actual practices of a state. The Table 3-10 excerpt shows state income and other tax rates for electric utilities. Finally, the Table 3-11 excerpt shows the exogenous financial data used for the model.

Table 3-12 summarizes the data acquired in the review of regulatory practices.

Table 3-9

NORMALIZATION VERSUS FLOW-THROUGH TREATMENT OF THE INVESTMENT TAX CREDIT[a]

State	Amount Normalized	Amount Flowed-Through	Normalization Method[b]		
			Rate Base	Cost of Service (Ratable Flow-Through)	Not Specified or Unclear[c]
Alabama	all				x
Alaska	all				x
Arizona[d]	varies				x
Arkansas	all			x	
California[d]	6% portion	4% portion		x	
Colorado	all			x	
Connecticut[e]	6% portion	4% portion			x
District of Columbia	6% portion	4% portion		x	
Delaware	all				x
Florida[f]	all				x
Georgia	all			x	
Hawaii	all				x
Idaho[g]	all				x
Illinois	all			x	
Indiana	all				x
Iowa	all			x	
Kansas	all				x
Kentucky	all				x
Louisiana	all				x
Maine	all			x	
Maryland	all			x	
Massachusetts	all				x
Michigan	all			x	
Minnesota	all				x
Mississippi	all				x
Missouri[h]	all				x
Montana	all				x
Nevada	all				x
New Hampshire	all			x	
New Jersey	all				x
New Mexico[f]	all			x	
New York[e]	6% portion	4% portion		x	
North Carolina	all				x
North Dakota	all				x
Ohio	all				x

Table 3-9 (contd.)

State	Amount Normalized	Amount Flowed-Through	Normalization Method[b]		
			Rate Base	Cost of Service (Ratable Flow-Through)	Not Specified or Unclear[c]
Oklahoma	all			x	
Oregon	all			x	
Pennsylvania[f]	all			x	
Rhode Island	all				x
South Carolina	all				x
South Dakota	all			x	
Tennessee		all			
Texas	all			x	
Utah[h]	all				x
Vermont	all				x
Virginia	all				x
Washington[j]	varies				x
West Virginia	all			x	
Wisconsin	all				x
Wyoming	all				x

[a] Information presented represents accounting methods applying to assets new prior to the Economic Recovery Tax Act of 1981.

[b] Definitions of normalization methods are taken from Reference 13.

[c] Unclear answers are those the authors had difficulty in interpreting. This does not mean that information provided was in any way inadequate.

[d] One utility flows-through 100 percent of the investment tax credit.

[e] One utility normalizes 100 percent of the investment tax credit.

[f] More than 90 percent is normalized. Most major utilities use ratable flow-through.

[g] One utility uses the ratable flow-through method.

[h] More than 90 percent is normalized.

[i] Two large utilities flow-through 100 percent.

[j] Of three major utilities, one flows-through 100 percent; one normalizes 100 percent; and one flows-through the 4 percent portion and normalizes the 6 percent portion.

Source: Reference 4.

Table 3-10
MAJOR STATE TAXES ON ELECTRIC UTILITIES (1981)[a]

State	Gross Receipts[b]	State Sales[c]	Local Sales[c]	Income[d]	Miscellaneous
Alabama	Municipal and local license tax 2-1/2% electric revenues	4%	2%	5%	Rental tax in some cities—4%; corporate franchise—$3 per mill based on par value of common and preferred stock; public utility license—2.2%; state regulatory commission fee—0.5%; hydro tax—.25¢/KWh
Alaska			3% Juneau and Douglas 1% outside corporate limits	9.4%	Juneau city use tax 1% for items purchased outside of Juneau
Arizona	Regulatory assessment 2/10 of 1% of gross receipts	4%		10.5%	
Arkansas	3%			6%	
California				State franchise tax—9.6%	
Colorado		3%		5%	
Connecticut	5%			10%	
District of Columbia	6%			State franchise tax—9.9%	Business license fee—insignificant
Delaware	Gross receipts tax —.1%; license tax 2% on gross revenues excluding residential and resale			8.7%	State franchise tax—maximum $100,000 on assets and share of stock; public utility tax—5%; regulatory tax —0.2% of intrastate operating revenue; use tax—2% on leases of tangible property

Table 3-10 (contd.)

State	Gross Receipts[b]	State Sales[c]	Local Sales[c]	Income[d]	Miscellaneous
Florida	Utility assessment fee—1/8 of 1% of gross operating revenues from intrastate business; gross receipts tax—1.5%	4% residential electricity sales exempt and purchases toward oil conversion		5%	
Georgia		3%	Some cities have supplement to state sales tax	6%	State franchise tax—4%
Hawaii	Public utility fee—1/4 of 1% of gross revenues			6.435%	Local franchise tax—2-1/2% counties and cities; public service company tax up to 8.2%
Idaho				6.5%	
Illinois	Gross receipts tax—5%; public utility tax on gross receipts—.008%	5%		State income tax—4%; personal property replacement tax on income—2.85%	State franchise tax—1.2%; personal property replacement tax on investment—0.8%
Indiana	1.35%	4%		3%	
Iowa				10%	
Kansas	State corporation commission tax—maximum of 1/5% of gross operating revenues			6.75%	
Kentucky	Millage rate			6%	
Louisiana		5%	2%	8%	State franchise tax—$1.50/$1000 capital and undivided profits
Maine		5%		6.93%	Corporation fee—insignificant
Maryland	2%	5%			Capital stock tax--varies

Table 3-10 (contd.)

State	Gross Receipts[b]	State Sales[c]	Local Sales[c]	Income[d]	Miscellaneous
Massachusetts				6.5%	
Michigan		Use tax—4%		2.35%	
Minnesota	Local—varies	5%		12%	Local franchise tax—varies
Mississippi		5% with exemption of residential customers		4%	State franchise tax—$2.50/$1000; local
Missouri		3.125%	Varies—3/8-1%	5%	State franchise tax—1/20 of 1% of assets
Montana				6.75%	Consumer council tax—0.09%
Nevada	State franchise tax—2% gross revenues mill assessments				Consumer advocate—0.000075%; PSC—0.0003%
New Hampshire	PUC tax—0.0013 of gross revenues of state			State franchise tax—9%	
New Jersey	7%	Insignificant—about 1% of taxes in 1979			State franchise tax—5% of assets; general assessment tax—about .9% of taxes in 1979
New Mexico	Gross receipts tax—3.5%; inspection and supervision fee—0.5% of gross revenues		2% of total revenues earned in any city	$90,000 + 6% of increment	
New York	Gross earning tax .75% from in-state sources and 4.5% on dividends paid/year above 4% of amount paid in capital employed in state			Gross income tax—3% exclusive of sales for resale	
North Carolina	6%			6%	

Table 3-10 (contd.)

State	Gross Receipts[b]	State Sales[c]	Local Sales[c]	Income[d]	Miscellaneous
North Dakota				7%	
Ohio	4%	4%			Highway use—insignificant
Oklahoma	2%	Varies—2-4%		4%	$1.25 per mill of invested capital; maximum tax $20,000
Oregon	PUC fee 0.15% per dollar of gross Oregon revenue; DOE fee .05% per dollar of gross Oregon revenue			Cities—overall about 1.75% of gross income; state income tax —7.5%	
Pennsylvania	4.5% of all revenues			10.5%	Capital stock tax—1% applies to capital stock value
Rhode Island	4%	State sales tax—6% residential exemption			
South Carolina	.3%	4%		6%	generation tax—0.5%/KWH
South Dakota	0.1% on gross retail revenues	4%			
Tennessee	3%			Excise tax—6%	State franchise tax—0.15%; franchise tax works as a credit against gross receipts
Texas	0.167% of gross revenues	State sales tax 5% residential exempt			
Utah	Less than 1%	4%			
Vermont	Gross receipts tax —4%; public service tax .0040 of gross operating revenues	3%		$17,150 + 7.5% of excess over $250,000	Generation tax—1.9% of asset's appraised value

Table 3-10 (contd.)

State	Gross Receipts[b]	State Sales[c]	Local Sales[c]	Income[d]	Miscellaneous
Virginia	1.125% of first $100,000, 2.6% on remainder; special commission tax—0.11% of revenues				
Washington	Business tax—3.6% of revenues intrastate	State sales tax—5%; utility and transmission fee—0.8% of sales to ultimate consumer			Franchise and occupational fee—1.0% (about); generation tax—.44% net generation; corporation license—insignificant
West Virginia	4%			State income tax—6%, offset by gross receipts tax	
Wisconsin	Remainder assessment .102% of revenue	4%		7.9%	
Wyoming	Maximum 0.3% on gross intrastate revenues				

[a] This table lists reported variations, qualifications, exclusions, deductions, and highest stage rates for taxes as provided by states. Marginal tax rates listed are generally applicable to class A utilities. Property taxes have not been included. All taxes when possible have been categorized according to their base. Others have been placed in the miscellaneous column. These taxes are as reported for 1981.

[b] Gross receipts tax is based on gross revenues. Gross revenues are also referred to as total receipts and total revenues.

[c] State and local sales taxes are based on total revenues from electricity sales.

[d] Income tax is based on net income unless otherwise specified.

Note: Percentages and fractions of percentages may be incorrectly interpreted.

Source: Reference 4.

Table 3-11
URGE STATE FINANCIAL DATA: SELECTED ARMS-REGION STATES

Item	Unit	Alabama	Arkansas	Connecticut	Delaware
Common equity portion of capitalization	fraction	.321	.312	.356	.353
Debt portion of capitalization	fraction	.581	.534	.510	.509
Preferred stock portion of capitalization	fraction	.098	.154	.134	.138
Accumulated investment tax credit	million $	54.9	32.3	48.9	34.2
Property tax and other taxes	fraction	.018	.013	.042	.019
State income tax rate	fraction	.050	.060	.100	.087
Base year accumulated investment tax credit	million $	54.9	32.3	48.9	34.2
AFUDC accumulation method	0=simple 1=compound	1	1	1	1
AFUDC calculation method	0=after taxes 1=other	0	0	0	0
Rate of return to common stock	fraction	.129	.150	.147	.150
Electric plant in service	million $	4009.0	2220.0	2936.0	1252.3
Net electric plant	million $	2922.7	1773.1	1798.5	970.0
Construction work in progress—electric	million $	1147.8	285.1	865.2	102.7
Accumulated direct construction costs—electric	million $	918.24	228.1	692.2	82.2
Construction work in progress—pollution control	million $	97.3	42.5	11.0	25.6
Accumulated direct construction costs—pollution control	million $	77.8	34.0	8.8	20.5
Total outstanding debt	million $	1879.1	825.1	1247.1	457.0
Prior common stock issuance	million $	1057.6	429.2	914.8	221.7
Prior preferred stock issuance	million $	359.1	209.5	310.5	108.9
Retained earnings	million $	98.9	88.4	340.5	113.8
Total current and accrued liabilities	million $	395.9	253.1	729.9	97.4
Total current and accrued assets	million $	402.0	116.8	496.5	154.1
Net working capital	million $	6.1	-136.4	-233.4	56.7
New preferred stock issued	million $	0.0	47.4	45.9	26.1
New common stock issued	million $	0.0	33.7	27.0	6.7
New long-term debt	million $	240.6	66.0	102.0	39.2
Total electric and current assets	million $	4538.6	2175.0	3420.9	1230.9
DOE 1980—total revenues from sales of electricity, private utilities	million $	1550.9	811.8	1379.1	436.9

Note: The EEI data are revenue from sales to ultimate customers and apparently include only intrastate revenue. For the DOE data, revenue from out-of-state sales may be included in both items, and sales to other utilities may be included only in the last item. EEI may include a larger number of utilities than does DOE.

Source: References 14 and 15.

Table 3-12
STATE DATA FOR THE AUSM FINANCIAL MODULE

- Percentage of construction work in progress allowed in rate base during construction
- Reasons for inclusion of construction work in progress in the rate base before project completion
- Utility policy toward rate base depreciation in states allowing construction work in progress in the rate base
- Utility policy toward tax depreciation in states allowing construction work in progress in the rate base
- Allowance for funds used during construction accumulation method allowed
- Policies toward allowance of construction work in progress in the rate base and method of accumulating allowance for funds used during construction
- Rate base adjustment for inflation
- Non-FERC methods of calculating allowance for funds used during construction
- Exceptions to including allowance for funds used during construction in rate base upon project completion
- Average service lives used to depreciate utility assets
- Recent rates of return allowed on common equity and the rate base
- Investment tax credit rates utilized by most utilities
- Electric utilities claiming 1 or 1.5 percent additional investment tax credit for employee stock ownership plans
- Normalization versus flow-through treatment of tax deferrals from accelerated depreciation
- Major state taxes on electric utilities
- State income tax rates for electric utilities
- Average number of months necessary for rate decisions
- Policies toward use of fuel price adjustment clauses
- Regulatory policies toward allowance of fuel procurement investments in the rate base
- Decommissioning accounting data for privately owned nuclear power plants
- Publicly owned electricity generation by state, 1980
- Regulatory commission responsibility for publicly owned electric utilities
- Financial data tables for all utilities in a state

Source: Reference 4.

3.4 Conclusion

In summary, the financial module for the AUSM contains two major components. One, the FINANC subroutine, computes the revenue a state's utilities are allowed to earn each year, as determined by the policies of its regulatory commission. The model allows for differences in state policies concerning the computation of afudc, the treatment of corporate income tax savings, and the inclusion of cwip in the rate base. In general, however, FINANC and the AUSM assume that commissions seek to implement normal policies that provide a prescribed fair cost to consumers and a fair return to investors.

In the second component, subroutine R602, receives actual revenue earned from the DEMAND subroutine and computes values for standard financial statements, maintaining the companies' base-year mix of financing options: long-term debt, preferred equity, and common equity. This subroutine also calculates several interest coverage and profitability measures that help indicate how well state regulatory policies enable utilities to maintain financial health under alternative air pollution control policies.

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4. THE COAL SUPPLY MODULE

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4.1 Introduction

The structure of the Advanced Utility Simulation Model (AUSM) is shaped by a fundamental tradeoff between the desire for extremely detailed presentations of the coal and electric utility sectors, on the one hand, and the desire for computational tractability, on the other. Similar models suffer from compromises made to sacrifice analytical detail for computational speed and simplicity. For example, the National Coal Model (NCM) developed by the Energy Information Administration (EIA), and the Coal and Electric Utilities Model (CEUM) developed by ICF, Inc. maintain a detailed representation of the coal supply sector but aggregate the coal washing and utility sectors to compensate [1,2]. On the other hand, the Utility Simulation Model (USM) developed by Teknekron Research, Inc. maintains unit-level detail in the utility sector, but at severe cost to the level of detail represented in the coal sector [3].

The approach used in the AUSM is to provide detail in both the coal and the utility sectors, but to break off coal mining, washing and transportation into a separate coal supply module. This module need not be solved simultaneously with the annually recursive AUSM. Functioning as a preprocessor, the coal supply module estimates the price of coal delivered to each of the 48 demand regions (states). Coal prices are computed for 11 sulfur dioxide (SO_2) categories and 3 higher heating value (HHV) categories for each time period. The delivered price is approximated by the sum of minemouth, cleaning and transportation costs. An efficient algorithm, described below, identifies the combination of supply region, raw coal type and cleaning technology yielding the least delivered cost.

Components of delivered cost vary over time according to user-specified escalation rates. Delivered prices are computed for selected years during the 1980 through 2040 time period; estimates for intervening years are approximated by a piecewise linear curve connecting these points. These projections extend for 30 years beyond the AUSM horizon so the model can take them into account when selecting coals for new power plants.

Scenario-specific assumptions in the state-level AUSM have only a negligible feedback effect on delivered prices calculated by the coal preprocessor. In the national-level model, however, due to the effects of depletion, scenario-specific assumptions may significantly affect minemouth costs for certain coal types in some supply regions. The national model is being designed to accommodate significant feedback effects of this type, assuring consistency through the interface between the coal supply module and the EPOS module (see Chapter 8). Development of this interface is being guided by analyses using the coal supply module to identify potential price-setting coals and to examine the sensitivity of minemouth cost to uncertainties in data on the size and distribution of coal reserves.

Minemouth costs for 1980 are expressed as a function of sulfur content and heating value using actual delivered prices reported by utilities, together with regional regression equations developed by Michelson and Green [4], who used data on actual shipments during the period 1975-80. Two sets of post-1980 minemouth cost projections are available, at the option of the user. The first employs user-specified escalation rates for aggregated regions and coal types. The second is based on model mine cost equations developed for EIA by McLean Research Center [5,6] for 1990 and beyond, with a linear interpolation between the actual 1980 figures and 1990 forecasts.

For each raw coal sulfur category and heating value, cleaning costs are computed for four technologies representing four levels of cleaning. Transportation costs from 35 coal supply regions to 48 demand regions are obtained from Ebeling [7].

The coal supply module is designed to accept several alternative types of mine-costing models. Some of these models and their underlying assumptions were developed for EIA by ICF [8] and are the same as those used in the CEUM. By operating the AUSM coal supply module in its stand-alone mode, these and other assumptions and costing models can be compared. As a stand-alone preprocessor, the module can be used for independent analysis of new technologies and various policies affecting coal mining, washing, and transportation.

Section 4.2 provides a more detailed description of the methodology for estimating minemouth costs and for determining the least-cost allocation that yields estimates of delivered prices.

4.2 Analytical Structure

The overall structure of the coal supply module is straightforward. One set of algorithms calculates the minemouth costs; another adds the costs of cleaning and transportation to obtain estimates of delivered prices. Figure 4-1 and Table 4-1 provide an overview of the module; details are presented below.

4.2.1 Minemouth Cost

The module is structured to accept coal supply data from a variety of sources. Econometric estimates of minemouth costs developed by Green [4] are used for 1980. One option extends these with user-specified escalation rates for the period beyond 1990. The 1980 estimates are calculated from regressions on actual coal prices reported for about 59,000 shipments during the 1975-80 period. The selection of these data and the default escalation rates are discussed in Section 4.3.

The second option is to base post-1980 projections on mine cost equations, using data on the quantity and distribution of coal reserves in each supply region and assumptions regarding the size distribution of the mines that would exploit these reserves. The current version is based on the cost equations developed for EIA by McLean [5,6] for EIA for nine model mines in connection with the 1981 EIA annual report to Congress [9].

The structure of the coal supply module allows updated EIA mine-costing algorithms to be used in the future. With only minor modifications, it will also be possible to insert econometrically based mine-costing equations such as those developed by Zimmerman [10,11] for comparison with the engineering-based equations developed for EIA.

The module structure for the "model mine" option can best be described in terms of three principal subprograms. The first two draw heavily on the EIA model--in fact, they are designed to accept virtually the same input data. These two subprograms subdivide coal reserves into the appropriate mine characteristics and compute key components of minemouth costs. A third subprogram combines these fixed and variable costs with other user-specified inputs to yield the total minemouth cost for each category of coal reserves, defined by mine size, seam thickness, depth, and/or overburden ratio. The relationship among these subprograms is shown in Figure 4-2, where QUANT allocates a quantity of coal type k in region i to

Figure 4-1
THE COAL SUPPLY MODULE

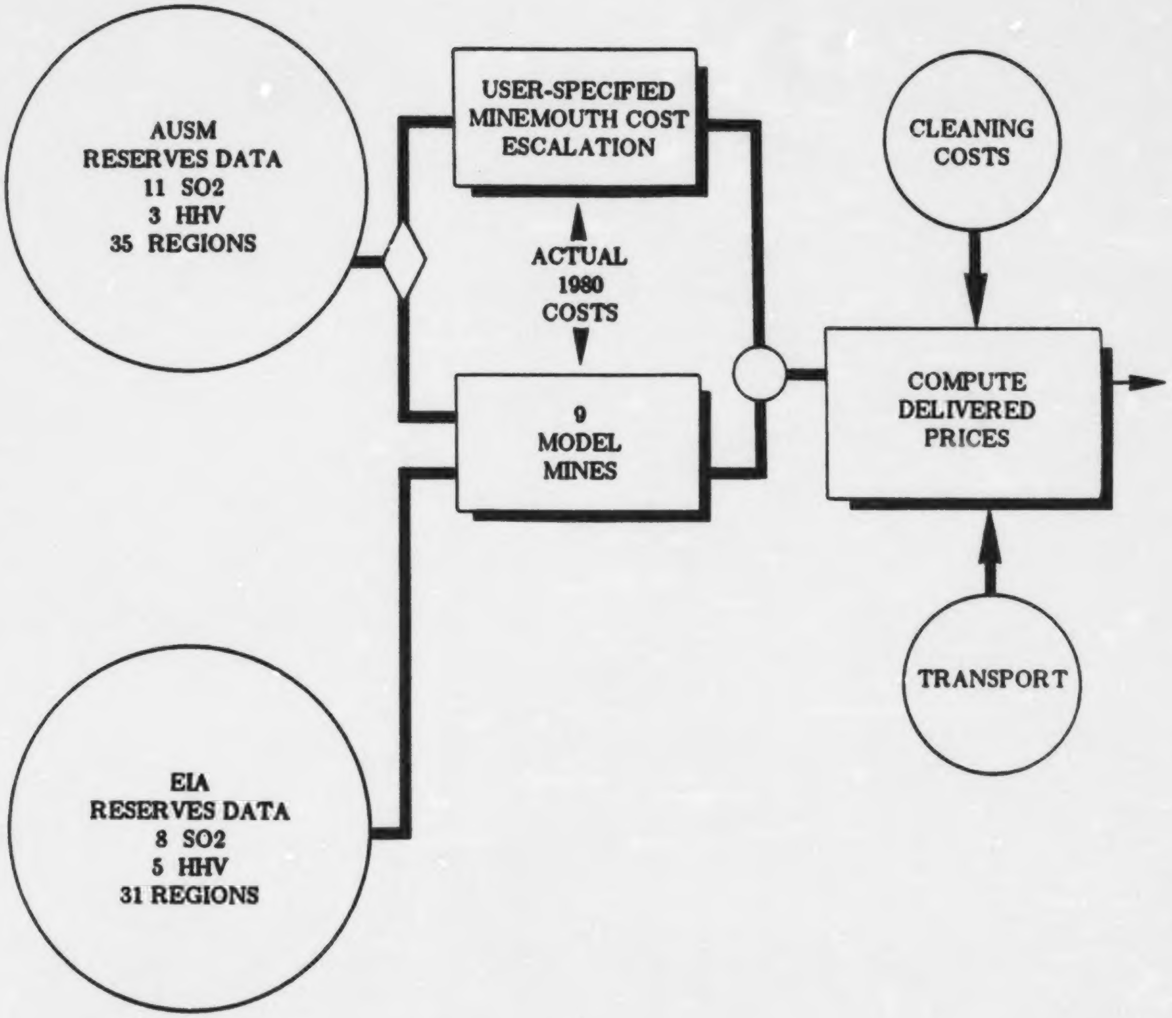
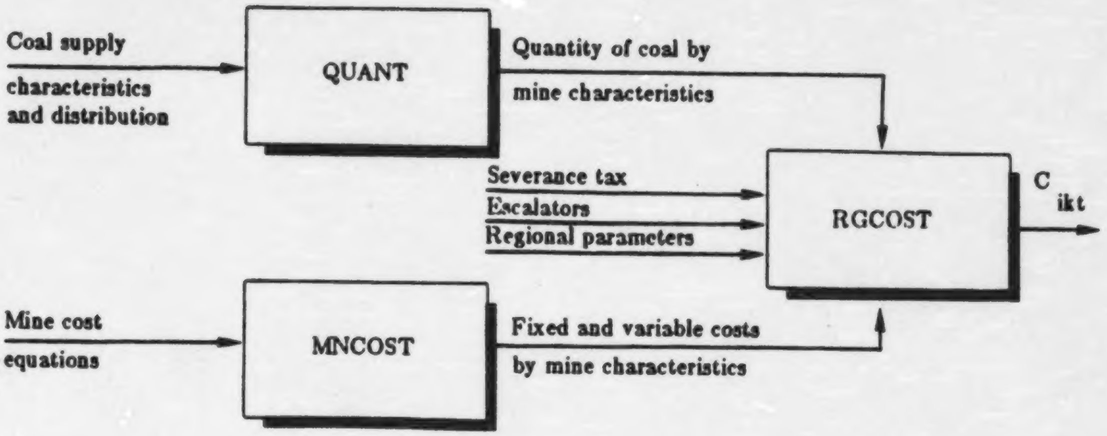

AUSM
RESERVES DATA
11 SO2
3 HHV
35 REGIONS
USER-SPECIFIED
MINEMOUTH COST
ESCALATION
ACTUAL
1980
COSTS
9
MODEL
MINES
CLEANING
COSTS
COMPUTE
DELIVERED
PRICES
TRANSPORT
EIA
RESERVES DATA
8 SO2
5 HHV
31 REGIONS

Table 4-1
USER-SPECIFIED INPUTS TO COAL SUPPLY MODULE

User-Specified Minemouth Costs	*Default Values*
User-specified escalation flag	0
Real escalation rate-western coal	.01
Real escalation rate-eastern coal	.03
Model Mine Parameters	
EIA reserves data flag (otherwise AUSM reserves data)	0
Inflation rate	.06
Real escalation rate-capital costs	0
Real escalation rate-wages	.01
Real escalation rate-power and supplies	0
Real escalation rate-other costs	0
Real after-tax rate of return on equity	.061
Real cost of debt	.015
Debt ratio	.30
Corporate tax rate	.50
Transportation Cost Multiplier	
Multiplier	1.0
Effective date	1985
Coal Cleaning	
Mandatory cleaning flag	0

Figure 4-2
CALCULATION OF MINEMOUTH COST OF COAL TYPE k
IN SUPPLY REGION i IN YEAR t


Coal supply
characteristics
and distribution
QUANT
Quantity of coal by
mine characteristics
Severance tax
Escalators
Regional parameters
RGCOST
C_{ikt}
Mine cost
equations
MNCOST
Fixed and variable costs
by mine characteristics

mine size S, seam thickness T, and depth D, or to overburden ratio R. MNCOST calculates the fixed costs (initial and deferred capital) and region-independent variable costs of mining a ton of coal in a mine of size S, in either seam thickness T and depth D, or overburden ratio R. RGCOST then calculates the minemouth cost of coal, C_{ikt}, adjusting for region-specific factors such as wage rates and severance taxes. The rationale for selecting the data employed in both of these methods for calculating minemouth costs is presented in Section 4.3.

The following subsections describe the use of mine cost equations to calculate the cost of coal produced by a hypothetical new mine opening in 1980. These equations are used to identify the seam thickness, depth, and mine size that are most economical to develop. Their application is relatively straightforward in the state-level AUSM, which identifies the most economical mines and projects future costs for such mines rather than depleting them and opening new ones. However, in the national-level AUSM, these same equations dictate the order in which new mines are opened and the manner in which reserves are depleted. In order for the national-level model to monitor depletion automatically without manual intervention by the user, the equations are developed in a manner different from the NCM and CEUM approaches, which were developed for static analyses for a specified year. Individual cost components are calculated separately so that cost data from mines opened in different years can be aggregated and escalated together, eliminating the need for modeling the operation of individual mines as their reserves are depleted. The actual tracking of depletion will be done only in the national-level model and will be described in the documentation of that model.

4.2.1.1 **Reserves as a Function of Mine Size, Seam Thickness, Depth, or Overburden Ratio.** This subsection outlines the subprogram QUANT, which has two basic functions. The first is to adjust the reserves data to account for mining recovery factors and reserves that are already committed, inaccessible, or illegal to mine. The second is to allocate remaining reserves to individual "deposits" characterized by mine size S, seam thickness T, and depth D, or overburden ratio R. The EIA methodology is only outlined here; a more detailed description can be found in a report prepared for EIA [8]. Table 4-2 shows the coal supply regions modeled, and tables 4-3 and 4-4 show the categories {S,T,D,R}, which define the "deposits" of reserves for which minemouth costs will later be calculated. The output of QUANT is the

Table 4-2
COAL SUPPLY REGIONS

AUSM Region[a]	EIA Region	BOM District
1. Pennsylvania-East	PA	1
2. Pennsylvania-West		2
3. Maryland	MD	1
4. West Virginia-East	NV	1
5. West Virginia-North		3
6. West Virginia-Panhandle		6
7. West Virginia-Southeast	SV	7
8. West Virginia-Southwest		8
9. Ohio	OH	4
10. Virginia-East	VA	7
11. Virginia-West		8
12. Kentucky-East	EK	8
13. Kentucky-West	WK	9
14. Tennessee-North	TN	8
15. Tennessee-South		13
16. Illinois	IL	10
17. Indiana	IN	11
18. Iowa	IA	12
19. Alabama	AL	13
20. Arkansas	AR	14
21. Oklahoma-East	OK	14
22. Oklahoma-West		15
23. Kansas	KN	15
24. Missouri	MO	15
25. Texas	TX	15
26. Colorado-North	CN	16
27. Colorado-South	CS	17
28. New Mexico-Northeast	NM	17
29. New Mexico-West		18
30. Arizona	AZ	18
31. Wyoming	WY Campbell County	19
32. Utah	UT	20
33. North Dakota	ND	21
34. Montana	EM WM	22
35. Washington	WA	23
South Dakota[b]	SD	21
Alaska[b]	AK	23

[a] AUSM regions were defined by disaggregating U.S. Bureau of Mines (BOM) districts wherever they were split by state lines. This allows AUSM results to be expressed by state and/or BOM districts.

[b] South Dakota was omitted on the basis that the cost of mining all coals from this region would always be prohibitive throughout the time horizon of this model [8]. Alaska is not treated in the AUSM simulation.

Table 4-3
SO_2 AND HHV CATEGORIES

	AUSM	EIA
SO_2 Category	*Pounds SO_2 per Million Btu*	
1	$\leq$ 0.59	$\leq$ 0.80
2	0.60 - 0.79	.81 - 1.20
3	0.80 - 1.19	1.20 - 1.27
4	1.20 - 1.49	1.27 - 1.67
5	1.50 - 1.99	1.67 - 1.85
6	2.00 - 2.49	1.85 - 3.35
7	2.50 - 2.99	3.35 - 5.00
8	3.00 - 3.99	$\geq$ 5.00
9	4.00 - 5.99	
10	6.00 - 7.99	
11	$\geq$ 8.00	
	Btu per Pound	
Rank	*Mineral Matter-Free Basis*	*As-Received Basis*
Bituminous	> 10,500	>10,000
Sub-bituminous	8,300 - 10,500	7,500 - 10,000
Lignite	< 8,300	<7,500

tons of reserves allocated to deep Q(S,T,D) and surface Q(S,R) deposits. These distributions are assumed to be independent of sulfur content and heating value, so the result is independent of the order in which the allocations are performed. For each coal type, reserves are allocated first among three general categories: surface, deep thin (28 inches to 42 inches), and deep thick (more than 42 inches). These fractions are treated as input data, allowing them easily to be varied to assess the sensitivity of results to uncertain parameters.

The actual allocation of underground reserves proceeds by assuming that "thick" and "thin" reserves are distributed uniformly within the intervals defined by their respective minimum and maximum thicknesses; quantities are allocated proportionally to each of the thickness categories. Next, these are

Table 4-4
COAL RESERVE CATEGORIES

Depth (feet)	Seam Thickness (inches)	Underground Mine Size (MMtpy)	Surface Mine Size (MMtpy)	Overburden Ratio
drift	28 - 36	0.1	0.1	20
400	36 - 48	0.5	0.5	25
700	48 - 60	1.0	1.0	30
1000	60 - 72	2.0	2.0	45
	>72	3.0	3.0	
			4.0	

allocated to depth categories using regionally specified fractions. Finally, they are subdivided in equal quantities among mine size categories smaller than and equal to the regionally specified maximums. These maximum mine sizes, expressed as a function of depth and thickness, were obtained by EIA from recent roof condition reports. It was assumed that they represent the largest mine sizes geologically possible because economies of scale call for opening the largest mines first. The amounts of coal allocated to each size category are sufficient to open an integer number of mines; remaining reserves are shifted to the next smallest mine size.

For surface mines the allocation proceeds first by assuming that reserves are distributed uniformly over a regionally specified overburden ratio interval. Reserves in that portion of the interval with R greater than 45 are ignored. Within each overburden ratio category, reserves are allocated among mine size categories using a regionally specified distribution obtained by EIA using data from each state.

The subprogram QUANT is designed to accept reserves data for any set of regions and coal categories. Data are available for the 1980 and 1981 EIA annual reports to Congress [12,9], and for the regions and coal types defined for the AUSM, which are summarized in Tables 4-2 through 4-4. All of these data are based on the U.S. Bureau of Mines [13,14,15] demonstrated reserve base, as updated by EIA in 1980 [16]. Table 4-5 summarizes the input data for QUANT; default values are taken directly from the 1981 EIA National Coal Model and reaggregated as necessary when applied to other regions and coal types.

Table 4-5
INPUTS TO QUANT

All Regions

Recovery factors for deep and surface mines

Each Region

Minimum and maximum overburden ratio

Minimum and maximum seam thickness

Percentage of surface reserves by mine size

Percentage of deep reserves by depth

Maximum size of deep mines by seam thickness and depth

Fraction of deep reserves inaccessible

Fraction of surface reserves illegal to mine

Each Region and Coal Type (HHV, SO_2)

Demonstrated reserves, 1980

Fraction of reserves in thin (<42") seams

Fraction of reserves in thick (>42") seams

Fraction of reserves in surface deposits

Fraction of reserves committed to production

EIA cleaning yields for deep and surface mines

4.2.1.2 Mine Cost Equations. MNCOST calculates four components of the minemouth cost of coal: initial capital, deferred capital, labor (productivity), and power and supplies. They are expressed as functions of the four mine characteristics: mine size S, seam depth D, and seam thickness T, or overburden ratio R. The cost equations are taken directly from McLean [5,6] and are shown in Tables 4-6 and 4-7. They characterize the nine types of "model mines" defined in connection with the latest available (1981) EIA annual report to Congress [9]. The program logic is identical to that employed for a different data base in the 1980 annual report [12], which included only two model mines. Therefore, the coal supply module can be adjusted to employ either set of assumptions and data. The current version is based on the nine model mines specified in the 1981 report.

The equations for the four cost components depend only on the model mine equations and, therefore, are not scenario dependent. Scenario-dependent inputs are described in Section 4.2.1.3. The four cost components need be calculated only once for each set of (S,R) and (S,D,T) for each of the model mines (assuming, in effect, that the mine is opened in 1980). MNCOST is then run only when the mine-costing equations or the category definitions of S, D, T, and R are changed. Labor productivity is assumed equal to that of a national average base case mine, and combined with region-specific wage data in RGCOST.

Specifically, the outputs of MNCOST are:

ICAP (S,D,T,R) = initial capital cost (1980$)
DCAP (S,D,T,R) = undiscounted sum of real deferred capital costs (1980$)
PROD (S,D,T,R) = labor productivity (tons/man-day)
PS (S,D,T,R) = power and supplies cost (1980$/yr)

The inputs and outputs of MNCOST are summarized in Figure 4-3.

The equations for the nine model mines in the 1981 EIA analysis are simple in form. The equations for capital costs are straightforward, but all operating costs are aggregated into one term, OC.

Table 4-6
COEFFICIENTS IN COST EQUATIONS FOR DEEP MINES

	Initial Capital (IC)				Deferred Capital (DC)				Operating Cost (OC)			
	a	b	c	e	a	b	c	e	a	b	c	e
Southern Appalachia	.55	35.48	.0104	0	0	18.72	0	0	0	26.68	0	.001
Northern Appalachia	1.08	43.56	.0104	0	0	14.08	0	0	0	25.12	0	.001
Midwest	1.73	41.60	.0104	0	0	13.80	0	0	0	20.83	0	.001
Far West	1.61	34.37	.0104	0	0	12.2	0	0	0	19.78	0	.001

Source: References 5 and 6.

Note: All total cost equations for deep mines are written in the form (MM$/yr) = a + bS + cD + eDS, where the values of a, b, c, and e are dependent on region.

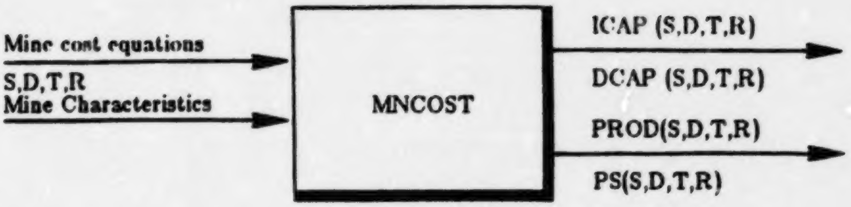
Table 4-7
COEFFICIENTS IN COST EQUATIONS FOR SURFACE MINES

	Initial Capital (IC)				Deferred Capital (DC)				Operating Cost (OC)			
	a	b	c	e	a	b	c	e	a	b	c	e
Central Appalachia	0	2.815	2.365	.419	0	2.318	1.947	.419	0	1.549	1.945	.419
Northern Appalachia	2.03	0	3.949	0	3.239	0	1.848	0	4.143	0	0	0
Midwest	0	2.713	2.671	.436	0	15.32	.1637	.436	5.607	6.406	0	.256
Far West	0	3.259	4.391	1	0	8.268	.1712	.577	9.262	4.555	0	1
Campbell County	0	1.934	11.943	1	0	4.552	3.19	1	0	3.058	6.967	1

Source: References 5 and 6.

Note: All total cost equations for surface mines are written in the form (MM$/yr) = a + bS^e + cRS, where the values of a, b, c, and e are dependent on region.

Figure 4-3
INPUTS AND OUTPUTS OF MNCOST


Mine cost equations
S,D,T,R
Mine Characteristics
MNCOST
ICAP (S,D,T,R)
DCAP (S,D,T,R)
PROD(S,D,T,R)
PS(S,D,T,R)

Deep Mines

$$\frac{ICAP}{S} = a + \frac{cD}{S} + b \tag{1}$$

$$\frac{DCAP}{S} = b \tag{2}$$

$$\frac{OC}{S} = b + cD \tag{3}$$

Surface Mines

$$\frac{ICAP}{S} = \frac{a}{S} + bS^{e-1} + cR \tag{4}$$

$$\frac{DCAP}{S} = \frac{a}{S} + bS^{e-1} + cR \tag{5}$$

$$\frac{OC}{S} = \frac{a}{S} + bS^{e-1} + cR \tag{6}$$

The coefficients a, b, c, and e are shown in Tables 4-5 and 4-6.

EIA disaggregates operating costs into components for labor and power and supplies in proportion to those for a base-case mine defined by McLean. Since regional variations in wages were not reflected in the base-case mine analysis, the labor cost component was used to determine the productivity instead. These productivity figures are later multiplied by region-specific wage rates as described in Section 4.2.1.3.

$$PS = OC * \frac{PSB}{OCB} \; (1980\$/yr) \tag{7}$$

$$PROD = \frac{WB}{OC} \frac{OCB}{LCB} * S \; (tons/man{-}day) \tag{8}$$

where OC = total operating cost(1980$/yr)

OCB = total operating cost for base case mine (1980$/yr)

LCB = total cost of labor for base case mine (1980$/yr)

PSB = total cost of power and supplies for base case mine (1980$/yr)

WB = wage in base case mine (\$/man-day)

S = mine size (tons/yr)

4.2.1.3 **Total Minemouth Cost of Coal.** The following equations for calculating total minemouth cost differ in several minor, but notables ways from those employed by EIA. The first, discussed in Section 4.2.1, is a matter of form: the AUSM equations treat the various cost components (labor, power and supplies, and so forth) differently in order to allow depletion to be monitored automatically in the national-level model. The second difference is a more realistic treatment of equipment depreciation periods in the AUSM. Finally, the AUSM determines the order in which new mines are opened by evaluating the present value of the stream of minemouth costs using the discount rate of the mine operator rather than the utility.

RGCOST determines a minimum minemouth selling price of coal type k in region i in time period t. The minimum selling price of coal in a supply region is assumed to be equal to the sum of the four regionally dependent components of the cost of mining coal, which are computed in MNCOST. Before summation, these components are adjusted to reflect scenario-dependent variables such as inflation rate, interest, return on equity, real escalation rates (for capital, labor, and power and supplies), reclamation costs, insurance costs, overhead, and routine coal preparation costs. QUANT and MNCOST need be run only for changes in the definition of coal types and in input data defining the distribution of reserves by size, thickness, depth, and overburden ratio. The outputs of QUANT and MNCOST to RGCOST are summarized in Table 4-8; exogenous inputs are listed in Table 4-9.

For each region i and coal type k, the present value of the minemouth cost for the life of the mine is calculated for each set of mine characteristics (S, T, D, and R). The mine having the lowest present value cost (normalized by mine size) is identified, assuming the mine is opened in the base year, 1980. For an identical mine opened in a future year, each component of the 1980 cost is separately escalated and summed. In the state-level model, the effects of depletion are ignored, so only this least-cost mine is considered. The national-level model will capture depletion effects by rank ordering mines having different seam thickness, depth, and so forth.

Table 4-8
ENDOGENOUS INPUTS TO RGCOST

Notation	Input	Source
$Q_{ik}(S,R)$	Strippable coal reserves by mine size and overburden ratio (tons)	QUANT
$Q_{ik}(S,D,T)$	Deep coal reserves, by mine size, depth, and seam thickness (tons) for region i and coal type k	QUANT
ICAP(S,R); ICAP(S,D,T)	Initial capital cost	MNCOST
DCAP(S,R); DCAP(S,D,T)	Deferred capital costs	MNCOST
PS(S,R); PS(S,D,T)	Cost of power and supplies	MNCOST
PROD(S,R); PROD(S,D,T)	Labor productivity	MNCOST

The present value of lifetime capital and operating costs is calculated on an after-tax basis. The average cost per ton in 1980 is represented, in constant 1980 dollars, as the sum of after-tax capital costs (levelized in real terms) plus operating costs.

The calculation of after-tax costs is complicated by the existence of two possible formulas for calculating the depletion allowance: It is equal to 10 percent of the selling price or 50 percent of the gross profit, whichever is less. A test must first be performed to determine which formula should be used for computing the tax. It is assumed that present values of the cost components can be used to identify which tax equation to use, even though the tax status of an actual mine may change during its lifetime.

The depletion allowance is 10 percent of sales (Case 1) if

$$PRE + PP \geq 1\frac{1-.5T}{4(1-T)}(PL + PPS + PO + PRD) + \frac{5-.5T}{4(1-T)} * PDPR \qquad (9)$$

Table 4-9
EXOGENOUS INPUTS TO RGCOST

Description	Default Value[a]
Financial parameters	
Inflation rate	.06
Real escalation rate - capital costs	0
Real escalation rate - wages	.01
Real escalation rate - power and supplies	0
Real escalation rate - other costs	0
Real after-tax rate of return on equity	.061
Real cost of debt	.015
Debt ratio	.30
Corporate tax rate	.50
Mine characteristics	
Basic preparation yield by region and coal type	b
Fixed reclamation costs by region ($/ton/yr)	b
License fees ($/clean ton/yr)	.10
Additional power and supplies (ADPS)	
Indirect cost of supplies (% of PS)	15
Labor	
Wage rate by region - surface ($/man-day)	b
- deep ($/man-day)	b
Additional labor (ADLAB)	
Payroll overhead (% of direct labor)	20
Indirect labor (% of direct labor)	15
Variable reclamation costs by region ($/ton)	b
EIA variable cost of cleaning by coal type and region ($/clean ton)	b
Exposure insurance by region (% of direct labor)	
- surface	b
- deep	b
Union welfare per day - surface ($/man-day)	5.85[c]
- deep ($/man-day)	5.85[c]
Union welfare per ton - surface ($/clean ton)	3.11[c]
- deep ($/clean ton)	3.11[c]
Other costs	
Fixed reclamation costs by region ($/ton/yr)	b
License fees ($/clean ton/yr)	.10
EIA annualized fixed cost of cleaning by coal type and region	b
Black lung tax - deep ($/clean ton/yr)	.50
- surface ($/clean ton/yr)	.25
- lignite	0

Table 4-9 (con't)

Description	Default Value[a]
Abandoned mine tax - surface ($/ton/yr)	.35
- deep ($/ton/yr)	.15
- lignite ($/ton/yr)	.25
Global royalty ($/ton)	0
Federal royalty by region - deep (percent of sales)	a
- surface (percent of sales)	a
Severance tax per ton ($/ton)	a
Severance tax levied as percent of total sales (percent)	a

[a] Cost data adjusted to 1980 dollars.

[b] Region-specific and/or coal-specific values.

[c] Defaults when regional values are not specified.

The depletion allowance is 50 percent of gross profit (Case 2) if

$$PRE + PP < \frac{1 - .5T}{4(1-T)}(PL + PPS + PO + PRD) + \frac{5 - .5T}{4(1-T)} * PDPR \qquad (10)$$

where PRE = present value of return on equity (1980$)

PP = present value of retirement of principal (1980$)

PL = present value of labor-related cost (1980$)

PPS = present value of power and supplies cost (1980$)

PO = present value of other nonescalating costs (1980$)

PRD = present value of debt cost (1980$)

$PDPR$ = present value of depreciation ($1980)

T = corporate tax rate (assumed = 0.5).

The present value of a stream of expenditures by a mine operator, f_n, is found from the expression

$$\textit{present value} = \sum_{n=1}^{L} \frac{f_n}{(1+r)^n(1+i)^n} \tag{11}$$

where f_n = expenditures in year n (current \$)

r = mine operator's real discount rate

L = lifetime of the mine

i = inflation rate.

The real discount rate r is defined using the weighted after-tax cost of capital, which is defined in nominal terms:

$$r' = (1 - T)Dr'_d + (1 - D)r'_e$$

$r'_d = (1+ r_d)(1+ i) - 1$

$r'_e = (1+ r_e)(1+ i) - 1$

where T = tax rate

D = debt ratio

r_d = real pretax interest rate on debt

r_e = real after-tax rate of return on equity.

then

$$r = \frac{1 + r'}{1 + i} - 1. \tag{12}$$

The present value (after tax) of the cost of opening a mine in 1980 and operating it for L years, per ton of output, is:

$$PV = \{A*(PRE + PP) + B*(PRD + PL + PPS + PO) + C*PDPR\} \div (Y*S*L) \tag{13}$$

where PV = present value (1980\$/ton)

Y = cleaning yield

S = mine size (tons/yr)

L = mine lifetime (yr)

and *A*, *B*, and *C* depend on the depletion allowance, the corporate tax rate T and the severance taxes and federal royalties where they are levied as a fraction F of total sales. If levied on a per ton basis, such taxes and royalties are included in PO. For Case 1,

$$A = \frac{1}{(1 - .9T)(1 - F)}$$

$$B = \frac{1-T}{(1 - .9T)(1 - F)}$$

$$C = \frac{-T}{(1 - .9T)(1 - F)}$$

For Case 2,

$$A = \frac{1}{(1 - .5T)(1 - F)}$$

$$B = \frac{1}{1 - F}$$

$$C = \frac{-.5T}{(1 - .5T)(1 - F)}$$

Equation 13 determines the order in which mines are opened. It will yield a slightly different result than the EIA approach, which is also used by ICF in the CEUM. The latter approach uses a relatively low utility discount rate, biasing the results toward relatively capital-intensive mines. The mine owner's discount rate was used instead in the AUSM analysis for several reasons. First, it was assumed that market forces lead owners to open mines on a least-cost basis as viewed from their own perspective, although competition may lead them to negotiate contracts with escalation schedules that look most favorable to electric utilities from their perspective. However, the stream of revenues must still cover the mine owner's present value of the cost of opening and operating the mine. Second, utilities would be expected to minimize the present value of the stream of total delivered costs, which include transportation along with minemouth costs. It was therefore decided that the NCM-CEUM approach of using the utility discount rate to minimize minemouth costs was unrealistic.

The subsections that follow present details of the calculation of each of the terms in Equation 13. The calculations are sufficient for determining the least-cost ordering of mine openings for the state-level

AUSM. The escalation of 1980 costs to future years is done separately for each cost component:

$$C_t = ((A * (CRE + CP) + B * CRD + C * DEPR)(1 + ek)^t$$

$$+$$

$$CL_o(1 + el)^t + CPS_o(1 + eps)^t + CO\,(1 + eo)^t) \div (Y * S) \tag{14}$$

where C_t = cost of a ton of coal in year t (1980\$/ton)

CRE = levelized return to equity (1980\$)

CP = levelized retirement of principal (1980\$)

CRD = levelized debt cost (1980\$)

$DEPR$ = levelized depreciation allowance (1980\$)

CL_o = labor-related costs in 1980 (1980\$)

CPS_o = cost of power and supplies in 1980 (1980\$)

CO = other costs in 1980 (1980\$)

and A, B, and C are previously identified tax-related coefficients, and ek, el, and eps are the real escalation of capital, labor, and power and supplies, respectively.

These real levelized costs were obtained by multiplying the present values by the capital recovery factor defined using the real discount rate calculated in Equation 12.

4.2.1.3.1 **Investment-Related Cost Components.** Four terms in Equation 13 are related to the stream of capital investments, K_n. Three of these–the present values of the return to equity, interest, and principal–are relatively straightforward to compute:

$$PRE = (1 - D) \sum_{n=1}^{L} r'_e * \frac{\sum_{m=1}^{n} K_m (1 + i)^m}{(1 + r)^n (1 + i)^n} \tag{15}$$

$$PRD = D \sum_{n=1}^{L} r'_d * \frac{\sum_{m=1}^{n} K_m (1+i)^m}{(1+r)^n (1+i)^n} \tag{16}$$

$$PP = \frac{\sum_{n=1}^{L} K_n}{(1+r)^L} \tag{17}$$

where D is the debt ratio. Note that it is assumed for simplicity that principal is paid in a lump sum at the end of the mine life.

To find K_n we follow the EIA methodology of spreading the deferred capital over the lifetime of the mine, evenly distributing 10 percent of deferred capital over the first and last quartile of the mine life and 90 percent over the central half of the mine life, and escalating each outlay to the year in which it is made:

$$
\begin{aligned}
K_n &= ICAP + DCAP\left(\frac{.05}{L_1}\right)(1 + ek) && n=1 \\
&= DCAP\left(\frac{.05}{L_1}\right)(1+ ek)^n && 2 \leq n \leq L_1 \\
&= DCAP\left(\frac{.9}{L_2 - L_1 + 1}\right)(1+ ek)^n && L_1 + 1 \leq n \leq L_2 - 1 \\
&= DCAP\left(\frac{.05}{L_1}\right)(1+ ek)^n && L_2 \leq n \leq L-1
\end{aligned}
\tag{18}
$$

where k_n = stream of capital investments (1980$)

$ICAP$ = initial capital investment (1980$)

$DCAP$ = aggregate deferred capital investment over life of mine (1980$)

L_1 = nearest integer to .25L

L_2 = nearest integer to .75L

ek = real escalation rate of capital costs

This equation implements the EIA assumption to permit the user to specify an escalation rate for the cost of opening new mines. It is based on input data shown in Table 4-9.

The fourth term in Equation 4-13 that depends on the stream of capital outlays is PDPR, the present value of depreciation deductions. EIA made a very crude approximation by computing the undiscounted sum of initial and deferred capital outlays in mixed current dollars, assuming it was all spent in the first year, and depreciating it over 30 years using a straight-line method. Rejecting that approach as unrealistic, a more sophisticated set of assumptions was developed based on consultations with industrial sources. Harry [17] suggested that machinery and equipment are depreciated over their actual 5- to 10-year lifetimes and that an assumption of straight-line depreciation would reasonably approximate current practice. Following this suggestion, it was assumed that all deferred capital expenditures (DCAP) are for replacement of machinery and equipment, that five-year lifetime equipment is replaced uniformly throughout the mine life, and that the increased outlays during the middle 50 percent of the mine life represent replacement of equipment having a 10-year life. This results in a stream of depreciation deductions $DEPR_n$, expressed in current dollars, which is used to calculate the present value needed for Equation 13:

$$PDPR = \sum_{n=1}^{L} \frac{DEPR_n}{(1+r)^n(1+i)^n} \tag{19}$$

4.2.1.3.2 **Operating Cost Components.** The stream of operating costs is found by escalating first-year costs:

$$PL = \sum_{n=1}^{L} \frac{LAB\ (1+el)^n}{(1+r)^n} \tag{20}$$

$$PPS = \sum_{n=1}^{L} \frac{PS\ (1+eps)^n}{(1+r)^n} \tag{21}$$

$$PO = \sum_{n=1}^{L} \frac{ON(1+eo)^n}{(1+r)^n} \tag{22}$$

where LAB = regionally adjusted 1980 labor cost (1980\$)

PS = regionally adjusted 1980 cost of power and supplies (1980\$)

ON = other 1980 costs by region (1980\$).

These three components of operating cost for a hypothetical mine opened in 1980 are obtained by summing the direct costs from MNCOST, the additional indirect (ADLAB and ADPS), and other costs shown in Table 4-9.

This concludes the calculation of minemouth costs using the model mine equations.

4.2.2 Delivered Prices

The transportation/cleaning subprogram determines the delivered cost of coal, defined as minemouth cost plus cleaning and transportation costs. It identifies the least-cost coal of type k delivered to each demand region j.

Each supply region contains many deposits of raw coal, having different sulfur contents, heating values, and minemouth costs. Raw coal may be cleaned at the mine before shipment to any of the demand regions, using any of several cleaning technologies. The solution algorithm therefore addresses the general problem of satisfying specific demands when many alternatives are available.

All raw coals are assumed to be supplied with the characteristics found in the demonstrated reserve base (DRB) input to QUANT. It is assumed that all western, lignite, and sub-bituminous coal is mined "clean," while all eastern bituminous coals undergo basic preparation, a process that crushes the coal and cleans it enough to restore it to the quality of the seam sample that formed the basis for the DRB. In the AUSM transportation cleaning algorithm, raw coals can be cleaned and thereby upgraded to as many as four lower SO_2 categories by four possible technical levels of cleaning. A coal is cleaned to one of these levels only if it results in the least delivered price to one of the demand regions. Cleaning matrices for each of 35 supply regions specify coal cleaning costs and the resulting changes in physical characteristics. Since higher heating value categories are defined to ensure that heating value remains within those limits during cleaning, separate matrices are provided for each of the three categories.

The coal supply module is also designed to utilize exogenous data on coal cleaning used in the 1981 EIA/NCM. Therefore, when EIA data are input to the AUSM coal supply module, the AUSM cleaning algorithm is bypassed (to avoid cleaning coals twice), and the minemouth costs are adjusted to reflect the EIA cleaning costs in the RGCOST subprogram.

The following subsections describe the structure of the AUSM transportation/cleaning subprogram in its most general form and the solution algorithm for the case where coal supplies are unconstrained. A full constrained-supply algorithm will be used in the national-level model.

4.2.2.1 **Transportation/Cleaning Equations.** Two physical properties, sulfur content and higher heating value, define a raw coal of type k. Let c_{ik} denote the cost per ton of mining ik raw coal.

The properties of raw coal may be changed by cleaning. The cost per ton of ik raw coal cleaned into type m is w_{ikm}. By allowing "dummy" cleaning (at zero cost and effect of the coal), we assume that all coal mined is also cleaned.

Consumers are grouped by state. Each state j has a demand d_{mj} in Btu of type m cleaned coal. The shipping cost per ton of cleaned coal from i to j is t_{ij}.

Coal is measured in raw tons, clean tons, and delivered Btu. One raw ton of ik coal yields y_{ikm} tons of type m clean coal. Thus, the total cost per Btu of type m coal cleaned from ik raw coal and delivered to j is

$$c_{ikmj} = [(c_{ik} + w_{ikm}) \div y_{ikm} + t_{ij}] \div (2000 HHV_{ikm}) \tag{23}$$

4.2.2.2 **Unconstrained Algorithm.** This section describes an efficient algorithm for computing minimum-cost unconstrained allocations restricted to any specified set. The algorithm is in two parts. First, for each mining region i and each demand mj, the algorithm finds the coal k that minimizes the total delivered cost of coal over all coal available at i; this is called "i's best offer to mj." (In the case of ties, i's best offer includes all the tied coals.) Second, for each mj, the algorithm determines which mining region i made the lowest cost best offer; this is called "mj's best coal supplier."

The details of the algorithm are illuminated by plotting, for each fixed i and m, the delivered cost per Btu of each raw coal available at i as a function of the transportation cost. For each coal ik that can be cleaned into m, the plot is a straight line with vertical intercept equal to the minemouth cost and slope equal to the inverse of the higher heating value. The pointwise minimum of the plots determines i's best offer to mj as a function of the transportation cost t_{ij}.

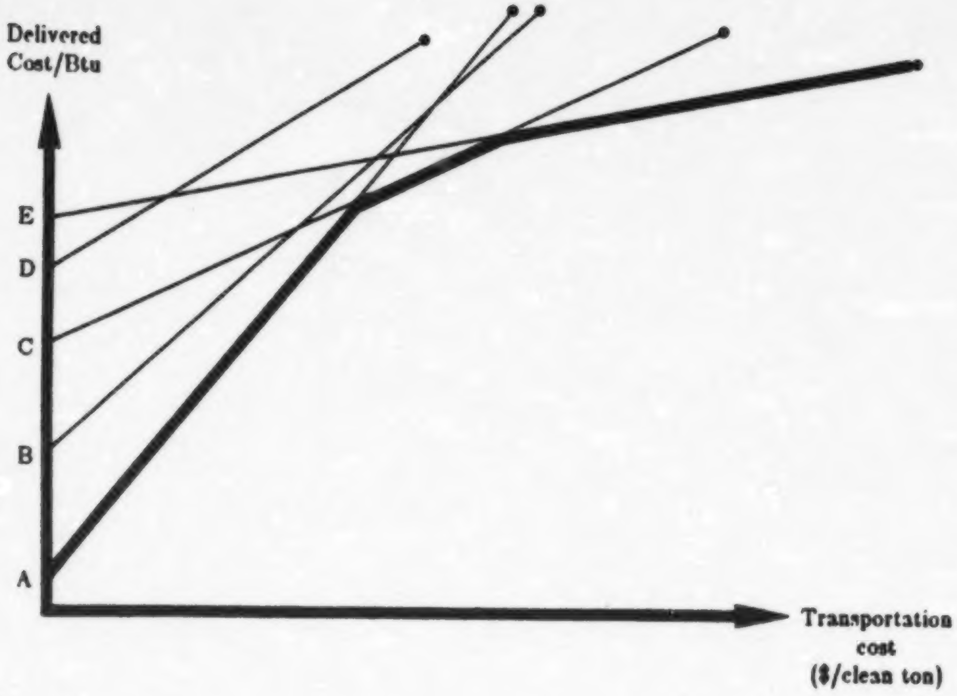
A sample plot is given for five coals (Figure 4-4). The pointwise minimum is indicated by the heavy curve; this curve coincides with the plots of coals A, C, or E depending on the transportation cost. Coals B and D may be eliminated. Each demand region is located on the abscissa by its transportation cost of coal from a particular supply region. Thus, there will be a similar plot for each coal type and each supply region.

Typically, many fewer coals define the minimum cost curve than there are customers. Thus, the algorithm determines i's best offer to each consumer by first determining the interval of transportation cost corresponding to each linear segment of the minimum cost curve. It then makes offers to each j based on the interval containing the transportation cost t_{ij}.

4.2.2.3 **Output of Delivered Price.** The unconstrained algorithm gives the cost of the least costly cleaned coal m delivered to region j. This is the primary output used by the AUSM. Raw and cleaned coal types are defined by both sulfur content and higher heating value. There are three higher heating values (bituminous, sub-bituminous, and lignite) and the same k sulfur categories defined earlier. In addition to the lowest delivered cost of coal, c_{ikmj}, the lowest delivered cost of local coal, c_{ikmj} $(i \in j)$, is calculated for use by the AUSM. Solutions are obtained for selected years during the period 1980 to 2040, using the appropriate minemouth costs and (escalated) transportation and cleaning costs for each of those years.

For the state-level model, the resulting delivered price is assumed to equal the delivered cost as calculated above. This assumption is discussed in Section 4.3.5. Cost data rather than rate data were used, allowing the least-cost allocation to be determined. In the national-level model, rents due to constrained supplies can then be calculated explicitly and considered in analyses of severance taxes and related policies.

Figure 4-4
TYPICAL SCREENING PLOT FOR SUPPLY REGION l
AND DELIVERED CLEANED COAL m



4.3 Data Choices

This section presents the rationale for selecting the data used by the coal supply module. It is divided into four subsections. The first describes the data on coal reserves and the selection of the sulfur dioxide and higher heating value categories. The second describes the choice of econometric projections for near-term coal costs and the selection of default values for long-term escalation of minemouth costs. The third describes the data underlying the "mine cost equations," which provide an alternative method for estimating minemouth costs. The fourth and fifth subsections describe the choice of data on coal cleaning and transportation.

4.3.1 Coal Reserves

The U.S. Bureau of Mines [13,14,15] is the primary source of data on coal reserves; these data provide the common basis for nearly all coal modeling analyses. This data base has been maintained and updated by EIA [16]. It is limited to a fraction of the resource base designated the "demonstrated reserves base." Thus it includes only the approximately 470 billion tons of known reserves that can be recovered using existing technologies. In Appendix B, Pechan presents arguments for including substantially larger estimates of less economical and/or undiscovered reserves. Our approach is to proceed first with the widely accepted DRB and to determine whether depletion effects are significant in the national-level AUSM model. Additions and corrections to this data base will be guided by those analyses.

DRB have been aggregated into 8 SO_2 categories by EIA [18] and 11 by Pechan (Appendix B) using slightly different recoverability criteria and assumptions regarding the sulfur content of reserves for which no SO_2 data were reported.

The 11 AUSM SO_2 categories were selected using two criteria. First, breakpoints were chosen at levels typically used to define emission standards for new and existing power plants. Second, the categories were defined such that the reserves in each category were roughly equal. The HHV categories were selected to conform as closely as possible to the ASTM D388 classification criteria for lignite, subbituminous, and bituminous coal. That classification, on a mineral matter-free basis, is reported by Baumeister [19]. Breakpoints are at 8,300 and 10,500 Btu per pound (mineral-matter free basis), which helps ensure that washing does not change the rank of the coal.

There are no EIA reports documenting all the data used in analyses underlying the 1980 and 1981 annual reports to Congress. Therefore, we relied on contractor reports and the input data tapes for the 1981 National Coal Model obtained from EIA by Pechan [18,22]. Starting in 1982, more complete and consistent documentation became available from EIA [1,18,20,21].

With one exception, all other default input data on coal reserves (Table 4-4) are identical whether the user selects the EIA or the AUSM allocation among SO_2 and HHV categories. That exception is in the adjustment for committed reserves: EIA estimates [18] are based on proprietary data obtained from mine operators, while AUSM estimates are derived using 1980 production data for each SO_2 category [4] and assuming an average remaining mine life of 15 years. This difference will affect depletion rates projected by the national-level model, but does not affect results from the state-level model.

4.3.2 User-Specified Minemouth Cost Projections

The user selects one of two methods for projecting post-1980 minemouth costs. In the first case, there is simple escalation at user-specified exponential rates for eastern coals and western coals; the default values are 1 percent. The second option is described in Section 4.3.3.

Minemouth costs for 1980 were developed by Michelson and Green [4] using the most detailed data available for the 1975-80 period. Covering more than 54,000 shipments of coal from individual mines to individual utilities, the estimates are based on regression analysis of minemouth cost data inferred by subtracting transportation costs (estimated using a county-level representation of rail and water transportation networks) from the delivered cost of each shipment reported on FERC Form 423. Besides SO_2 and HHV categories, the regression accounted for United Mine Worker wages, oil prices, ash content, size of shipment, and other variables. Spot market transactions were eliminated from the data base in an effort to detect long-term trends reflected in contract purchases. Moreover, there was no way to separate cleaned from raw coal in the data base. Moreover, such potentially significant factors as the date of contract negotiation and the general state of upheaval in the coal industry were not included in the analysis. These results, which are based on the most detailed set of actual data available on the variation of minemouth price with sulfur content, appear to explain about half of the variation in coal prices during the 1970s.

When the results of this analysis were compared with the weighted average of actual 1980 delivered prices (spot plus contract) in each state, extremely large variations were observed. Most prices differed by at least 15 percent, and variations exceeding 50 percent were not uncommon. Although Green and Michelson demonstrate reasonably good agreement with published EIA data on minemouth costs aggregated over all sulfur categories, and their methodology ensures close agreement at the national level for average delivered price, there was a significant and systematic bias apparent when national average delivered prices were compared by sulfur content. On average, Green and Michelson's estimates ranged from 20 percent low for low-sulfur coal to 20 percent high for high-sulfur coal, compared with actual delivered prices. It is not clear whether this resulted from the influences of the spot market or from other factors affecting the coal market in 1980. This bias is ameliorated in future years by the assumption of exponential escalation rates, thus widening the differential between costs of low and high sulfur coals.

Therefore, it was decided to replace the 1980 estimates of delivered prices by the actual weighted average values reported by utilities [25]. This was done more realistically to reflect the actual market forces affecting 1980 coal prices and to provide a more consistent point of departure for the simulation. However, the Green and Michelson estimates were used to indicate the region of origin and physical characteristics of the coal. Thus, it is assumed that the analysis of contract prices yields insights into the allocation of coal, but that actual 1980 experience reflects more accurately the factors affecting its price. To simulate a smooth transition from the actual 1980 prices to the 1990 estimates, the 1985 results were replaced by the mean of the 1980 and 1990 prices.

4.3.3 Model Mines

The second option the user may select for projecting post-1980 minemouth costs is one based on engineering cost models of nine types of hypothetical new mines that could be opened in the various regions. The input data listed in Table 4-8 were selected to provide a consistent point of departure from the data used by EIA in the mid-term analysis for its 1981 annual report to Congress. All can be changed for various AUSM scenarios, and parameters within the model mine equations (Tables 4-5 and 4-6) can be varied in the course of sensitivity analyses to quantify depletion effects in the national-level model.

To facilitate comparison with EIA analyses, most of the default values in Table 4-8 were taken directly from the 1981 National Coal Model data tapes [21,22]. The few exceptions are some financial parameters that are expected to be altered frequently by users. The inflation rate was set equal to the same default value assumed in the other AUSM modules. Real escalation of wage rates was set at 1.0 percent, somewhat less than the 1.4 percent rate typical of the 1960-80 period, when productivity was increasing [23]. The lower default rate was chosen partially to compensate for the implicit assumption of constant productivity for each mine type in model mine equations. Data on real costs of debt and equity capital were not readily available for the coal industry, because most of the largest coal companies are held by other diversified corporations. Therefore, it was decided to use aggregated data for the 500 largest corporations averaged over the period 1926-1978 [24]. These rates, 1.5 percent and 6.1 percent, respectively, actually overestimate actual values for the last 20-year period, but are substantially lower than the values assumed in other models [2,21]. The debt and equity ratios were based on an informal review of values reported by large corporations in Moody's manual. EIA data were not used for default values of these parameters because the reports on which they were based were either out of date or poorly documented. Users wishing to replicate EIA inputs should set the inflation rate at 0.0736 and wage escalation at 0.0. Setting the costs of debt and equity capital at 0.0436 and 0.118, respectively, would yield the weighted real after-tax rate of 0.08 assumed by EIA [21].

It is recognized that model mine equations may yield significantly different costs than actual 1980 coal prices, which reflect the amount of excess capacity, old contracts, and other conditions in the coal market at that time. Therefore, it is assumed that by 1990 minemouth coal costs gradually approach the levels indicated by the model mine equations. In the state-level model, costs are interpolated linearly from the actual 1980 levels to the 1990 values obtained from the model mine equations. This implicitly assumes that eventually minemouth prices will approach the cost of opening new mines. Real escalation beyond 1990 is determined by escalation of the individual cost components in the mine cost equations. In the national-level model, depletion effects will increase these escalation rates.

An important factor affecting actual 1980 coal prices is the existence of long-term contracts between individual mines and power plants. This is accommodated in the AUSM by utilizing the most detailed data available—the 1980 delivered price of coal at each generating unit—and assuming that price escalates at the same rate as the delivered price of coal from that same supply region, as computed by the coal supply module. Only the *magnitude* of cost increases is obtained from the coal supply module; these are added to the actual 1980 values for individual plants. The resulting prices are used until the plant switches to a different coal, at which time the absolute value of the delivered price of the new coal is obtained from the coal supply module.

4.3.4 Washing Data

The coal washing data utilized by the coal supply module consist of a number of items for each washing process that takes coal of a particular type and raw sulfur category and moves it into a lower sulfur category. These data are:

1. The washing yield (tons of clean coal per ton of raw coal).
2. The washing cost (dollars per ton of raw coal).
3. Clean coal higher heating value (Btu per pound).
4. Clean coal ash content (fraction).

The sulfur content of clean coal is set at the midpoint of the appropriate interval defined in Section 4.3.1.

The only comprehensive data set describing the washability of U.S. coals has been built and maintained by the U.S. Bureau of Mines [25]. Each coal in this data base was processed using a simple preparation plant model [26], which represents four different technical levels of preparation. This model adjusted the original washability data (which refer to tests made under laboratory conditions) for the "inefficiency" of commercial washing equipment and provided estimates of the cost (in dollars per raw ton) of reducing the sulfur content of the original seam quality coal.

The 710 samples in the revised data base were then pooled into 18 "washability regions" (which are aggregations of the 35 AUSM supply regions). A set of regression analyses was performed to establish each of the four data items specified above as functions of desired sulfur removal and the properties (ash, sulfur, and Btu content) of the original seam quality coal.

The final step was to take the properties of seam quality coal in the reserves data base as developed by Pechan (see Appendix B) and to use the equations developed from the regression analyses to attempt to wash each of the characteristic coals into lower sulfur categories. The final results are presented in the format of a triangular matrix for each supply region and coal (higher heating value) type.

A full description of the steps taken to establish the coal data for the supply module is given in Appendix C.

4.3.5 Transportation Data

Data on transportation costs were obtained from an analysis performed by Ebeling [7] specifically for the AUSM project. Centroids of AUSM supply and demand regions were selected based on an analysis of coal production and utilization in 1980. The analysis employed an extremely detailed network model of U.S. rail and water transportation systems consisting of 54,000 railroad stations and 30,000 docks. Engineering cost estimates were based on the 1978 Interstate Commerce Commission uniform rail costing system and recent Corps of Engineers data, and converted to 1980 dollars using the cost recovery index developed by the Association of American Railroads [27]. Results from this same model were used by Green and Michelson [4] to estimate least-cost routings between individual power plants and mines, which they subtracted from FERC Form 423 data to obtain estimates of 1980 minemouth costs. An earlier version of that same model was used to develop the cost estimates initially employed in the CEUM by ICF [2].

Ebeling's analysis provided cost estimates for two routings: (1) the shortest all-rail route following mainline trackage whenever possible and (2) a combined rail-water route. The resulting transportation costs were disaggregated into fixed and variable costs, and further into labor and other important cost components, facilitating the specification of scenarios in which cost components escalate at different rates. Fixed costs were approximated by reported depreciation in one case, and by the fully amortized costs of rolling stock and trackage capacity expansion in another. The former, an approximation to short-run marginal costs was selected for use in the initial AUSM analyses. The latter will be used in later analyses to address "bottleneck" effects, since they provide an upper bound on long-run marginal costs. The cost of alternative routings would lie within this range.

Loading and unloading costs were included in the mine cost equations and power plant cost estimates; the transportation costs are limited to those incurred by the shipper. In fact, the mine cost equations included the cost of trucking coal to unit train loading facilities in some cases. No trucking costs were estimated by Ebeling, even though trucking, rather than rail, is used for some short hauls. Instead a minimum transportation cost of $1 per ton was assumed, to override any lower estimates that appeared in the data due to the proximity of entroids chosen. This amount corresponds roughly to the cost of a 50-mile unit train haul, or a similar truck haul considering the loading/unloading cost savings that would result.

The AUSM coal supply module includes a transportation cost multiplier to reflect anticipated increases due to rail deregulation and other factors not reflected in the input data. The default value, 1.71 in 1990 and beyond, was obtained from an EIA analysis of the projected effects of coal rate deregulation. Actually EIA projected an eventual 90 percent increase (by 1995) but the assumptions underlying their analysis make it clear that the results should be viewed as upper bounds [28]. Therefore, the 1990 estimate of 71 percent was adopted and interpreted as a long-term cost ceiling for the default data set.

Engineering cost data, rather than actual transportation rate data, were selected for two reasons. First, it is felt that future (deregulated) rail transportation costs will be influenced more strongly by actual costs than by historic (regulated) rates. Second, it is important to maintain consistency with the cost-based approach taken for minemouth costs and washing costs. This will allow the constrained-supply coal module for the national-level model to solve for the least cost allocation, and to quantify the rents associated with alternative coal allocations. It is more important to quantify the rents and include them in the delivered price than to determine their distribution among the mining, cleaning, and transportation sectors. It is felt that this distribution depends on many site-specific factors too detailed for inclusion in an aggregated model such as the AUSM.

4.4 Results of Stand-Alone Analyses

This section illustrates the type of results obtained from the state-level coal supply module, using very preliminary transportation data and assuming no washing.

Table 4-10 shows estimates of delivered coal costs for the state of Pennsylvania based on default values for the user-specified minemouth cost escalation option. These estimates, for the 1990 period, are indicative of the type of data provided as input to the AUSM.

Using the coal module as a stand-alone model, useful information can be obtained that will simplify construction of the national-level version, which will deal explicitly with the effects of depletion. The first step, some results of which are shown below, was to conduct preliminary analyses focusing only on coal deposits that are so abundant they might be expected to place a "cap" on the price of potentially deplet-

Table 4-10
DELIVERED COAL PRICES--PENNSYLVANIA
(in dollars per million Btu)

SO2	HHV	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
1	1	3.42	3.43	3.44	3.45	3.47	3.48	3.49	3.50	3.51	3.52
2	1	3.01	3.03	3.06	3.09	3.12	3.15	3.18	3.21	3.24	3.27
3	1	1.80	1.81	1.83	1.85	1.86	1.88	1.89	1.91	1.93	1.94
4	1	1.78	1.79	1.81	1.82	1.84	1.86	1.87	1.89	1.90	1.92
5	1	1.71	1.73	1.75	1.76	1.78	1.80	1.81	1.83	1.84	1.86
6	1	1.68	1.70	1.71	1.73	1.74	1.76	1.78	1.79	1.81	1.82
7	1	1.59	1.61	1.62	1.64	1.65	1.67	1.68	1.70	1.71	1.73
8	1	1.57	1.58	1.60	1.61	1.63	1.64	1.66	1.67	1.69	1.70
9	1	1.52	1.53	1.54	1.56	1.57	1.59	1.60	1.62	1.63	1.64
10	1	1.41	1.42	1.43	1.45	1.46	1.47	1.49	1.50	1.51	1.53
11	1	1.39	1.40	1.41	1.42	1.43	1.44	1.46	1.47	1.48	1.49
2	2	3.73	3.73	3.74	3.75	3.76	3.76	3.77	3.78	3.79	3.79
3	2	3.75	3.76	3.76	3.77	3.78	3.79	3.80	3.80	3.81	3.82
4	2	3.85	3.86	3.87	3.88	3.89	3.90	3.91	3.91	3.92	3.93
5	2	4.46	4.48	4.51	4.54	4.57	4.60	4.63	4.66	4.69	4.72
6	2	4.11	4.12	4.13	4.14	4.15	4.16	4.17	4.18	4.19	4.20
4	3	6.19	6.22	6.25	6.28	6.31	6.34	6.37	6.40	6.42	6.45
5	3	3.62	3.62	3.62	3.63	3.63	3.63	3.64	3.64	3.64	3.65
6	3	3.82	3.82	3.82	3.82	3.83	3.83	3.83	3.84	3.84	3.84
7	3	3.95	3.95	3.95	3.96	3.96	3.96	3.97	3.97	3.97	3.98
8	3	6.34	6.37	6.40	6.43	6.45	6.48	6.51	6.54	6.57	6.60
9	3	4.23	4.24	4.24	4.25	4.26	4.27	4.27	4.28	4.29	4.30

able coals having similar characteristics. Subsequent analyses will explore the extent to which certain smaller and more costly coal supplies can be omitted from the model without affecting the optimal solution significantly.

4.4.1 Minemouth Cost and Cumulative Depletion

The minemouth cost of coal varies as a function of time due to two factors: (1) real escalation of its component costs and (2) depletion. In an effort to isolate the effects of depletion, results of the preceding analyses were tabulated for the case of mines opening in 1980 for each of the coal "deposits" defined by the parameters (S,T,D,R). The result is a hypothetical supply curve expressing minemouth cost as a function of cumulative depletion. Each "deposit" corresponds to a step on the supply curve.

Table 4-11 shows the parameters defining such a supply curve for a coal of type k in region i. Besides the minemouth cost C_{ikl} and the quantity of reserves Q_{ikl} associated with each "step" on the supply curve, the table contains additional information useful for identifying coals whose cost may escalate rapidly due to early depletion. One of these parameters is the actual 1980 production, q_{ik}^{80} [4]. This value is used in columns 1 and 2 to normalize the uncommitted reserves data adjusted for mining recovery fractions, and to express these data in terms of the number of years remaining at 1980 production rates. Column 3 contains simular information, normalizing all costs by that of the least costly deposit (l = 1). The last four columns list the costs and quantities in natural units. Also shown is a parameter

$$\alpha_{ik} \equiv \sum_{l=1}^{L} Q_{ikl} \ C_{ikl} \div (Q_{ikL} \ C_{ikL})$$

which measures the "flatness" of the supply curve. This is important because for many coals the smallest, deepest,and thinnest deposits are unlikely to be developed during the foreseeable future; therefore all steps on the supply curve above a threshold value may be omitted from the analysis. The determination of such threshold values is described in a later section; suffice it to say at this point that the flatness of the supply curve will determine the effect on reserve estimates of uncertainties in the assumed distribution of reserves over (S,T,D,R) deposits.

Note that for the western Kentucky coal shown in the table, the 1980 price is significantly greater than the minemouth cost given by the EIA mine cost equations. This discrepancy probably results from

Table 4-11
TYPICAL COAL SUPPLY CURVE

Region: Kentucky-West
Coal Type: $3.0 \leq SO_2 < 4.0$
1980 Production = 2.64 million tons/year
HHV = 24.7
Price = 120 cents/million Btu

Years Remaining		Normalized Cost	Cost		*Potential Production (million tons)*	
Each Step	Cumulative		cents/MMBtu	$/ton	Each Step	Cumulative
5	5	1.00	87	21.72	15	15
5	11	1.04	91	22.56	15	30
5	17	1.08	94	23.40	15	45
3	20	1.22	107	26.49	9	54
4	24	1.22	107	26.49	12	66
5	30	1.38	120	29.86	15	81
5	36	1.38	120	29.86	15	96
5	42	1.53	134	33.24	15	111
5	47	1.53	134	33.24	15	126
1	48	2.48	217	53.79	3	129
1	49	2.55	223	55.31	3	132
1	51	2.61	229	56.67	3	135
3	54	2.79	245	60.61	9	144

Alpha = .52

two factors. The first is that the mine cost equations may produce estimates that are too low, due to assumptions made in the underlying contractor reports [5,6]. These equations have been updated recently by EIA and could be included in later versions of this model. The second set of factors accounting for the difference between cost and price results from market conditions not modeled, or from depletion effects which cannot be captured in the current version of the model, but which will be captured by the "constrained supply" version now being developed.

Although the costs are based on a hypothetical mine opened in 1980, Table 4-11 does provide a useful point of departure for studies of coal depletion, and for sensitivity analyses of the assumed resource distributions over (S,T,D,R). The analyses in Sections 4.4.3 and 4.4.4 are based on these data, and are therefore subject to the following caveat: Reserves depleted in the near term will be relatively unaffected by the 1980 cost assumption, but the relative costs of coal from mines opened in the distant future may differ significantly from those shown in the table. In other words, differential escalation of the costs of opening various types of mines will change the relative position of "steps" on the supply curves over time, especially those steps corresponding to the more costly reserves that are not likely to be mined within the next 10 to 20 years. Therefore, the data base shown in Table 4-11 was used only for identifying the analyzing coal deposits subject to near-term depletion; repeating the same calculations using mine costs for the year 2000 yields a similar table useful for long-term analyses.

4.4.2 Identification of Price-Setting Coals

Data of the type shown in Table 4-11 reveal that some coals (defined by region, sulfur dioxide content, and heating value) have extremely large reserves and relatively flat supply curves. Over an appropriately chosen time horizon, these coals may be expected to define ceilings on the cost of coal delivered to each demand region. Such cost ceilings can then be used to identify coal deposits too costly to be economically mined; they can be excluded in order to simplify analyses dealing with that time horizon. This section describes the method used to define such coals likely to be price setters over the next 30 years.

The first step was to identify all coals with sufficient uncommitted reserves to meet the utility demands for that type of coal over a 30-year period at 1980 consumption rates. Total national demand was obtained by summing FERC data on coal use at each generating unit in the nation [25]. The 50 coals that met this criterion are listed in Table 4-12.

Next, the cleaning and transportation model was used to allocate (only) these "abundant" coals among the demand regions, assuming supplies were unconstrained at minemouth costs corresponding to the first step on the supply curve. The calculated 30-year production levels were checked to determine whether minemouth costs would be expected to increase significantly. If so, the minemouth cost was reset to the higher level and the calculations repeated until delivered costs stabilized. It was assumed that demands for coal of a given sulfur content could be met by lower sulfur coals. The resulting set of 29 "price-setting" coals is identified in Table 4-12; twenty-one of the large-supply coals were eliminated by this analysis. Table 4-13 shows an example of the minemouth costs used in the final calculation, and the demand regions where they cap the delivered price of coal. By comparing SO_2 categories it was determined that two of the price-setting coals were cleaned to meet demands for lower sulfur coal, and that eighteen substituted for higher sulfur coals. The last column shows the number of years that 1980 demands (in the regions shown) could be met by the quantity of price-setting coal available at indicated value of minemouth cost.

4.4.3 Depletion

The price-setting coals identified earlier will place an upper limit on the amount of coal mined in the United States during the foreseeable future. Since minemouth costs may depend on mine size, seam thickness, seam depth, and overburden ratio (S,T,D, and R, respectively), there will be deposits characterized by certain values of these parameters that will be too costly to mine. That is, the additional costs of transportation and cleaning would result in a delivered cost higher than that of one of the price-setting coals in *every* demand region j. It is important to identify such reserves so they can be deleted from coal allocation analyses in order to reduce computational complexity. A method for identifying such reserves is described below. For some coals the result turns out to be unambiguous, while for others the results are extremely sensitive to uncertainties on key input data: specifically, the assumed distribution of reserves among the categories {S,T,D,R}. The methodology can be described using Figure 4-5. It shows a supply curve for coal type k mined in region i. Each step on the supply curve shows the cost of coal produced

Table 4-12
LARGE-SUPPLY COALS

SO2 Category (lb/MMBtu)	1 <.6	2 .6-.8	3 .8-1.2	4 1.2-1.5	5 1.5-2.0	6 2.0-2.5	7 2.5-3.0	8 3.0-4.0	9 4.0-6.0	10 6.0-8.0	11 >8.0
Supply Region	CO-N[a]	WV-N[a]	WV-N	KY-E	IL[a]	PA-W	PA-E[a]	PA-W	OH[a]	WV-PH[a]	OH
	CO-S	WV-SE[a]	WV-SW	CO-S[a]	WY	WV-N	PA-W		KY-W[a]	OH	IL[a]
	WA[a]	WV-SW[a]	KY-E[a]	NM-N[b]	WY[b]	TX[b]	ND[a,c]		IL[a]	KY-W[a]	IA
		CO-N	WY[a]	WY[a,b]	ND[a,c]	WY				IL[a]	MO
		CO-S[a]	WY[b]			WY[b]					
		NM-NE[a]	UT[a]			ND[a,c]					
		WY[a,b]	ND[b]			MT					
		MT[a]	MT[a,b]								
		MT[a]									

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[a] Price-setting coal (1980)

[b] Sub-bituminous

[c] Lignite

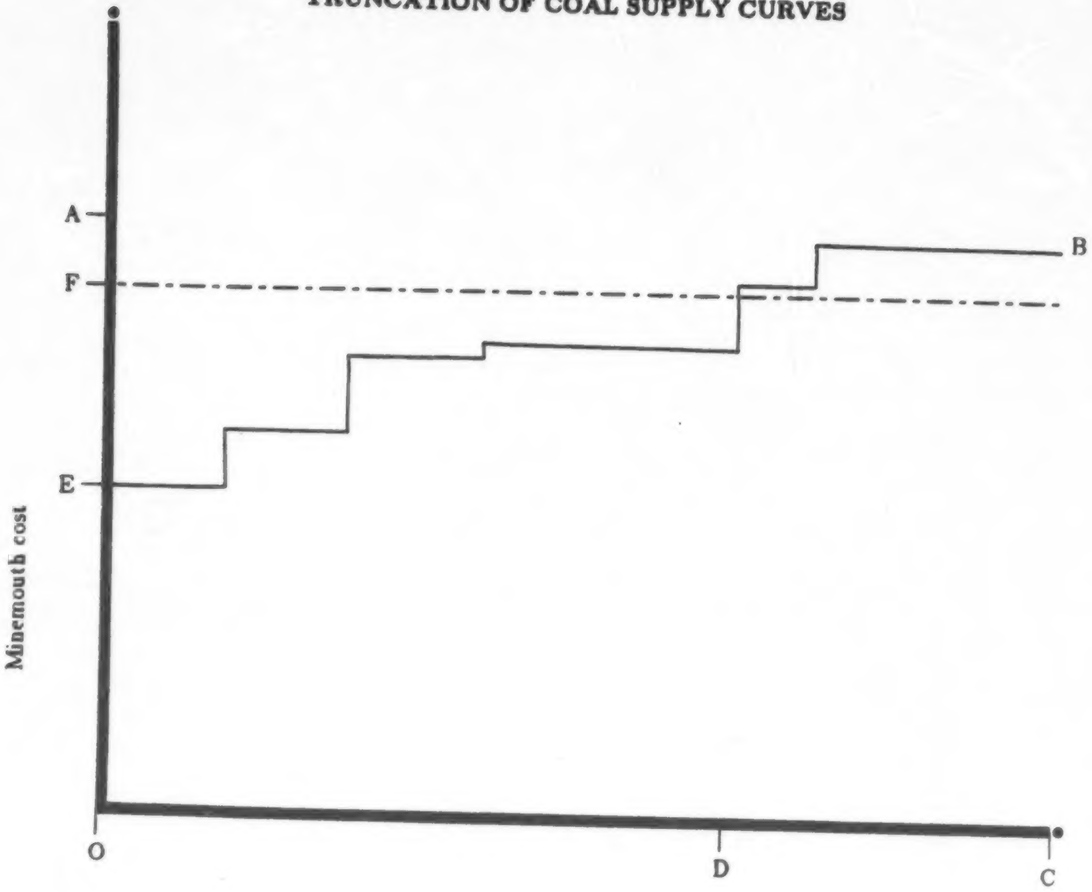
Table 4-13
MARKETS SERVED BY TYPICAL PRICE-SETTING COAL

Coals Having Large Reserves			Potential Production (million tons per year for 30 years)	Minemouth Cost (cents/MMBtu)	Price-Setting Coals				
Region	SO2	HHV			Demand Region	SO2	HHV	Delivered Cost (cents/MMBtu)	Year's Supply at 1980 Usage
KY-E	3	1	9.	116.	TN	3	1	152.	[a]
KY-E	3	1	9.	116.	IN	3	1	152.	165
KY-E	3	1	9.	116.	KY	2	1	142.	114
KY-E	3	1	9.	116.	TN	3	2	152.	[a]
KY-E	3	1	9.	116.	IN	3	2	152.	[a]
KY-E	3	1	9.	116.	KY	3	2	142.	[a]
KY-E	3	1	9.	116.	KY	4	1	142.	824
KY-E	3	1	9.	116.	KY	4	2	142.	[a]

[a] No 1980 demand for this coal type.

Figure 4-5

TRUNCATION OF COAL SUPPLY CURVES



from a particular deposit (S,T,D,R) by a hypothetical mine opened in 1980. FG represents the minemouth cost above which this ik coal cannot compete in any demand region j with one of the price-setting coals defined earlier. It therefore follows that no more than D tons (of the C tons of total ik reserves) are likely to be developed in the foreseeable future. If E is greater than F, no coal of type ik would be developed. The supply denoted by point D in Fig. 4-5 represent the quantities of coal that could be developed in a particular region before a price-setting coal excluded it from the market. This result, unfortunately, will be highly uncertain for some coals, because of uncertainties in the data used by EIA to distribute reserves over "deposits" defined by (S,T,D,R).

To identify coals having costs extremely sensitive to the assumed distributions over (S,T,D,R), the parameter α_{ik} is defined:

$$\alpha_{ik} \equiv \frac{OEBC}{OABC} \tag{24}$$

Values of $\alpha_{ik} \approx 1$ identify coals having minemouth costs relatively insensitive to uncertainties in the distribution of those reserves. Such supply curves may be aggregated to reduce the number of constraints required in the optimal allocation problem. Values of $\alpha_{ik} << 1$ identify coals having costs that vary significantly with depletion, and that must be represented by a supply curve having a larger number of steps.

The first step in the analysis is to determine the ceiling cost H, denoted C_{ik} for each region and coal type:

$$C_{ik} = \max_{l} c_{ikl} \tag{25}$$

such that for each (ikl), $C_{ikl} \leq (P^{\max}_{mj}\ HHV_{ikm} - t_{ij} - w_{ikm}))\ y_{ikm} \quad V_{m,j}$

where	c_{ikl}	is the cost per ton of ik coal corresponding to step l on the supply curve
	$P^{\max}_{mj}$	is the maximum delivered cost per MMBtu of type m coal in demand region j
	HHV_{ikm}	is the higher heating value of ik coal after cleaning to type m
	w_{ikm}	is the cleaning cost per clean ton
	y_{ikm}	is the cleaning yield (Btu/Btu = ton/ton)

t_{ij} is the transportation cost per ton

Using the values of P_{mj} obtained from the allocation of price-setting coals in Section 4.4.3, all values of C_{ikl} were screened; those not satisfying the above inequality for all m,j combinations were deleted. Some coal types could be eliminated entirely in certain regions, when the first step on the supply curve (C_{ikl}) exceeded the cost ceiling. In other cases, only the highest steps on the supply curve were eliminated. Table 4-14 is a revision of Table 4-11, reflecting these deletions from the reserves data. Note that α_{ik} now indicates the "flatness" of the truncated supply curve. For most coals it exceeds 0.90, indicating that most coals may be approximated by only one or two "deposits" in the constrained-supply analysis. Another result of this screening process is a list for each coal demand (mj) of the economic coal deposits (ikl) that may serve it, and the corresponding delivered costs $P_{iklmj} \leq P_{mj}^{max}$. This information indicates for each (mj) the preferred order in which various supplies would meet that demand. By focusing attention on the relatively small number of supplies that together are adequate to meet 1980 demands for more than 60 years, it is possible to further reduce the number of pathways (iklmj) modeled in the constrained-supply optimization problem. The 60-year demand criterion is felt to be sufficiently conservative (given the other approximations inherent in the analysis) to determine the number of coal supplies (ikl) that need be modeled in the constrained-supply optimization problem.

4.5 Summary and Conclusions

At its present stage of development, the coal supply module allows the AUSM to draw on minemouth cost estimates based either on user-specified escalation rates, or on two sets of coal reserves data and model mine cost equations. The initial emphasis on this diverse approach was requested by EPA because of the intense debate among proponents of the alternative approaches and the need for the AUSM to be credible and useful to each. Future development of the coal supply module will be aimed at including and examining the effects of depletion, in the context of the national-level AUSM. Development and implementation of an efficient constrained-supply algorithm to combine minemouth, washing, and transportation costs depends on the extent to which results of stand-alone module analyses identify a smaller

Table 4-14
TYPICAL COAL SUPPLY CURVE (TRUNCATED)

Region: Kentucky-West
Coal Type: $3.0 \leq SO2 < 4.0$
1980 Production = 2.64 million tons/year
HHV = 24.7
Price = 120 cents/million Btu

Years Remaining		Normalized	*Cost*		*Potential Production (million tons)*	
Each Step	Cumulative	Cost	cents/MMBtu	$/ton	Each Step	Cumulative
5	5	1.00	104	25.72	15	15
5	11	1.03	107	26.57	15	30
5	17	1.07	110	27.41	15	45
4	21	1.19	123	30.50	12	57
3	24	1.19	123	30.50	9	66
Alpha = .91						
5	30	1.44	149	36.99	15	81
5	36	1.44	149	36.99	15	96
5	42	1.60	166	41.07	15	111
5	47	1.60	166	41.07	15	126
1	48	2.43	252	62.41	3	129
1	49	2.49	259	64.05	3	132
1	51	2.55	265	65.53	3	135
3	54	2.71	282	69.83	9	144
Alpha = .54						

number of economically viable coals that need to be modeled in such detail. The preliminary results outlined above provide reason to believe that the required number of constraints can be kept to a manageable number.

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5. THE POLLUTION CONTROL MODULE

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5.1 Introduction

5.1.1 Objectives

The pollution control module of the Advanced Utility Simulation Model (AUSM) quantifies selected energy, economic and environmental impacts based upon regulatory requirements for air pollution control at new or existing coal-fired plants. The module also selects the least-cost means of complying with specified emission standards at coal-burning power plants or units. Given the scope of the AUSM effort, the pollution control module seeks to balance the potentially conflicting objectives of model simplicity (to minimize computational time and data requirements) and model complexity (to achieve sufficient sensitivity to important physical, economic and policy variables).

5.1.2 Analytical Approach and Rationale

5.1.2.1 Overview of Model Structure. The pollution control module is composed of three types of analytical models: 1) system performance models, 2) economic cost models and 3) decision criteria models.

System performance models are used to determine various power plant energy flows, and mass flows including capacity penalties and pollutant emission rates. The models also are used to determine key design parameters for pollution control systems such as the specific collection area of an electrostatic precipitator. Typically, these models utilize data for specific power plants provided by the AUSM unit inventory files.

Economic models are used to calculate the capital costs and annual revenue requirements of various pollution control options. Many of the values in these models are quantitatively determined from the various physical performance models using site-specific data. Other economic parameters are evaluated for specific technology designs or classes of plant.

Finally, decision criteria models are employed to select an appropriate set of alternative fuels, fuel blends, and control technology options that comply with specified air pollution emission regulations at a given power plant or generating unit, and to select from among these the most economical option. Such decision models typically involve criteria based on least levelized cost over the remaining plant life. Other decision models determine the technical applicability of specific fuels and/or control technology options at specific sites, as well as options applicable only to new or existing generating facilities.

Technical judgment is involved in defining both the final forms of models of these types and their interactions. An important guiding principle was the set of policy applications and issues that the AUSM was intended to address. Thus, the pollution control module should be expected to give good estimates of the aggregate costs to utilities of complying with various emission control scenarios at the national, regional, and state levels. Given the large number of facilities involved in the analysis (and the lack of systematic site-specific data of many types), it would not be reasonable or appropriate to consider all site-specific factors that determine control costs and compliance options at individual units or plants. Rather, certain "typical" conditions, systems, and criteria are defined and applied in conjunction with selected site-specific parameters of special importance. Thus, while calculations are carried out at the level of individual power plants or generating units in order to capture significant detail, numerical results would be valid only at higher levels of aggregation.

The remaining subsections in this introduction summarize key aspects and approaches used in developing the three types of models that constitute the pollution control module. Details of the model development and structures are presented in Section 5.2.[1] Summary discussions on data choices and illustrative results follow in Sections 5.3 and 5.4, respectively.

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[1] These discussions are intended for a technical audience already knowledgeable about the specific technologies or subject areas being addressed.

5.1.2.2 Economic Cost Models. The pollution control module is used to estimate capital cost and annual revenue requirements of technologies for air pollution control. The following items are presently modeled:

1. **Nitrogen Oxide Control Systems**
   Low NO_x burners
   Overfire air
   Limestone injection multistage burners (LIMB)

2. **Flyash Removal Systems**
   Cold-side electrostatic precipitator
   Hot-side electrostatic precipitator
   Fabric filter (baghouse) collector

3. **Sulfur Dioxide Removal Systems**
   Wet limestone scrubbing (with or without forced oxidation)
   Dry lime scrubbing (spray dryer)
   Limestone injection multistage burners (LIMB)

4. **Solid Waste Disposal Systems**
   Ponding
   Landfill

Models of physical coal cleaning systems for sulfur and ash removal also have been developed. These are discussed separately in Appendix C.

5.1.2.2.1 Pollution Control Capital Costs. The capital cost (or first cost) of a system or system component includes all expenditures necessary to establish its operation. Capital cost items are usually classified as either direct or indirect. Typical elements of each are summarized in Table 5-1. The total capital cost (TCC) of any component i in the system is then the sum of its direct and indirect costs. Indirect costs are often specified, or can be estimated, as a percentage of total direct cost (TDC). This

Table 5-1
ELEMENTS OF CAPITAL COST AND REVENUE REQUIREMENTS

Capital Costs		*Revenue Requirements*	
Direct	Indirect[a]	Variable	Fixed[b]
Equipment	Construction expense	Administration	Ad valorem tax
Labor	Contingencies	Fuel	Cost of capital
Land	Contractor fees	Maintenance labor	Depreciation
Materials	Engineering	Maintenance materials	Income tax
Structures	Interest during construction[c]	Operating labor	Insurance
Total Direct Cost (TDC)	Startup costs	Plant overhead	Interim replacement
	Working capital	Raw materials	Tax credits
		Supervision	
		Utilities	
		Total Variable Cost (TVC)	

[a] *Each item in this list may be estimated as a fraction of total direct cost (TDC). Typical values of total indirect cost factors are 50 to 100 percent of TDC. Values may vary with specific component, plant size, and local conditions.*

[b] *Each item in this list may be estimated as a fraction of total capital cost (direct plus indirect). Typical values of the total fixed charge factor are 10 to 20 percent of total capital cost. In the AUSM, fixed charge factors are calculated for individual plants or units as described elsewhere in this documentation.*

[c] *In the AUSM, interest during construction is calculated separately based on other scenario variables.*

fraction is known as the indirect cost factor, f. Thus, the total capital costs of any system component i can be expressed as:

$$(TCC)_i = (TDC)_i\,(1 + f_i) \qquad \text{[Eq 1]}$$

This equation is used to calculate total capital costs in the AUSM. The indirect cost factors are independent variables (parameters) of the model that can be specified by the user. Representative (default) values for individual technologies are discussed in Sections 5.2 and 5.3. The total direct cost of each component is calculated from the analytical models described in Section 5.2. These models utilize several site-specific physical parameters derived by the performance models also described in Section 5.2. All capital costs in the AUSM are expressed in 1980 dollars and escalated to other years using real escalation rates. Capital cost models are based on engineering cost estimates for new plants and are applied to existing plants through use of a "retrofit factor" multiplier.

5.1.2.2.2 **Pollution Control Revenue Requirements.** The revenue requirement of a major system component refers to the financial resources required to operate it over some period of interest, usually a year. Elements of the revenue requirement are categorized as variable costs or fixed costs. Variable costs depend on the extent of plant utilization, while fixed costs do not. Typical items of fixed and variable costs are summarized in Table 5-1. Fixed costs are often a direct function, or an estimated fraction, of the total capital cost. This fraction is called the fixed cost factor, F. Thus, the total annual revenue requirement (ARR) for component i is

$$(ARR)_i = (TVC)_i + (F_i)\,(TCC)_i. \qquad \text{[Eq 2]}$$

In this equation, the total variable cost $(TVC)_i$ is calculated from models of individual technologies presented in Section 5.2. Total capital cost, $(TCC)_i$, is given by Equation 1, while the fixed cost factor is derived from economic and financial assumptions in conjunction with the AUSM financial module (see Section 5.2.9).

5.1.2.2.3 **Levelized Cost of Control.** Economic decision criteria for choosing among power plant pollution control options typically employ the concept of a "levelized cost," a measure of the cost over the full lifetime of the plant. This is the measure generally employed in the AUSM. Details of the calculation procedure and its implementation in choosing a least-cost option are presented in Sections 5.2.9 and 5.2.10. The levelized cost reflects both the capital and operating costs of a pollution control system (such as a scrubber), plus the cost of the fuel used for power generation. This is essential in comparing options that may involve choosing between a cleaner but more expensive fuel and a "dirtier," less expensive fuel that requires additional flue gas cleaning systems. The levelization method also incorporates the effect of assumptions regarding future inflation rates and real cost escalation in fuel, equipment, and other areas that may significantly affect pollution control decisions.

5.1.2.3 **Power Plant Performance Models**. Calculation of pollution control costs and pollutant emission rates requires knowledge of several parameters unique to individual power plants. These primary data are contained in the electric generating unit inventory computer file (described in Appendix A) that services the AUSM. Here, the nature of performance parameters and models used in the pollution control module are described briefly. Details are presented in Section 5.2.

5.1.2.3.1 **Effect of Data Limitations**. It should be recognized that the rationale for choosing specific model forms and analytical approaches often is influenced by limitations in available data rather than by considerations of computational cost. By data limitations, we mean information that is not generally available in the type of routinely updated, computer-read files that characterize the AUSM plant and fuel data bases. For example, the AUSM data base on U.S. coal characteristics does not contain information on coal moisture content, ash fusion temperature, ash alkali content, or ultimate analysis, all of which may affect coal selection and pollution control system design, and which, if available, could be employed in more sophisticated analytical models without significantly increasing computational complexity. Similarly, the unit inventory lacks certain technical and economic details that also could be utilized to refine analytical calculations, such as better information on boiler design characteristics, excess air rates, flue gas temperatures, and operating costs. Such limitations notwithstanding, the AUSM data base remains the most comprehensive currently available for analysis on a national level. Nonetheless, analytical models must be developed that recognize and reconcile data base limitations as well as possible. Specific examples are discussed in the context of detailed model development (Section 5.2).

5.1.2.3.2 **Plant Energy Requirements**. Net power plant energy conversion efficiencies are characterized in the AUSM by a plant or unit "heat rate," which specifies the fuel energy input to the boiler required to produce a unit of net electrical energy output. This is a site-specific piece of data read from the unit inventory data base (for existing plants) or specified by the AUSM planning module (for new plants). The unit heat rate, size, and capacity factors together determine the total annual energy requirement. As discussed later, multiple units at a given plant may be analyzed individually or in aggregates (depending on applicable air pollution standards) to arrive at total plant energy flows.

When pollution control systems are added, their auxiliary energy requirements (for steam and/or electricity) lower the net electrical capacity, resulting in a unit or plant "derating." The magnitude of this capacity penalty is calculated by performance models included within the overall pollution control module. Details of these models are presented in Section 5.2 in the discussions of individual pollution control technologies. Fuel energy flow rates in the AUSM are then calculated from knowledge of the fuel's higher heating value (included in the data base) and the plant or unit capacity factor, as determined by the dispatching module.

5.1.2.3.3. **Plant Mass Flows**. The design and cost of pollution control systems generally depend on the maximum or design flow rates of one or more quantities, since this determines the required system size or capacity. For example, the cost of a flue gas cleaning system (for flyash collection and sulfur dioxide removal) depends strongly on the quantity of flue gas resulting from combustion of fuel and air in the boiler. In addition, the mass flow rates of sulfur and ash in the combustion products also significantly affect control system size and cost. Such quantities are calculated in the AUSM based on mass and energy balance algorithms (see Section 5.2.2). Several of the site-specific parameters that may influence such calculations are read from the data base or, more commonly, estimated for certain classes of plants where site-specific information is unavailable. The mass flow rate of coal (or other fuel) to a plant follows directly from knowledge of the total energy flow rate (discussed above) and fuel heating value.

5.1.2.3.4 **Pollutant Emission Rates**. This is a special case of plant mass flows. Air pollutant emission rates are calculated either from a fuel mass balance (knowing the removal efficiencies of pollution control devices) or from empirical "emission factors" that relate pollutant emissions to a primary mass or energy flow (e.g., pounds per ton of fuel burned). The latter employ standard factors published by the U.S. Environmental Protection Agency (EPA) for various fuel/boiler combinations (see Section 5.2.2).

Solid waste emissions also are calculated in the model. For ash, this is determined from a simple mass balance using known coal properties. For sludge produced by a flue gas desulfurization (FGD) system, this is based on empirical factors related to the sulfur removal rate (see Section 5.2.6).

5.1.2.4 **Decision Criteria Models**

This is the third type of analytical model incorporated in the pollution control module of the AUSM. Decision models primarily concern the treatment of existing coal-fired power plants faced with a more stringent emission control scenario, though several concern new power plants as well. The principal kinds of decisions or issues needing resolution through a formal "model" (or rule) include:

1. Decision about whether a given (alternative) coal can be burned in a particular boiler (because of its physical properties).
2. Selection of all candidate coals for a particular plant or unit.
3. Identification of complying and noncomplying coals (with respect to a sulfur emission standard).
4. Identification of complying blends of coals.
5. Identification of candidate pollution control technologies.
6. Identification of interactions among pollution control systems (e.g., effects on precipitator performance of switching to a lower sulfur coal).
7. Identification of the least-cost control option for a particular plant or unit (given other constraints on that choice from the points above).
8. Determination of the effects of lead times needed to implement alternative control systems.

In each case, the general approach is to seek as realistic a simulation as possible based on knowledge of industry practice, weighed against data limitations and computational efficiency. Details of the specific decision rules or criteria currently incorporated in the AUSM appear in Section 5.2.10.

5.2 Analytical Structure[2]

5.2.1 Introduction

This section presents details of the structure and development of the analytical models of the AUSM used to calculate the total direct cost and total variable cost of flue gas cleaning and solid waste disposal system for a coal-fired power plant. These models are based largely on the work of Molburg [1], with subsequent developments by the other authors. Power plant pollution control system performance models needed to calculate costs also are included in this section.

Sections 5.2.2 through 5.2.8 document the technology-specific models. These subsections also include overviews of the data sources and general design basis underlying the economic models for each control technology studied. Additional details concerning many of the numerical values of design parameters affecting cost and performance calculations appear in Section 5.3.

Certain power plant, fuel and regulatory parameters affect the design and cost of environmental control systems directly. Section 5.2.2 presents the model equations used to calculate or estimate these parameters, which are employed subsequently in the models of pollution control technology performance and cost.

5.2.2 Power Plant Flow Rates, Pollutant Removal Requirements and Emission Rates

5.2.2.1 Coal Mass Input Rate. The coal mass input rate is calculated for each coal-boiler combination. It provides a consistent basis for the calculation of other system mass flows such as the sulfur dioxide and particulate emission rates. The coal mass input rate is calculated for a plant operating at 100 percent capacity and based on the commonly available plant performance specifications in Equation 3. For one day of operation at full capacity,

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[2] The following sections contain many technical details that the reader may wish to review only briefly.

$$\dot{M}_{coal} = \frac{MW_g * HR * 1000}{HV * 2000} \qquad \text{[Eq 3]}$$

where $\dot{M}_{coal}$ = coal mass input rate on as-received basis (tons/hr)
MW_g = plant gross capacity (MW)
HR = plant gross heat rate (Btu/KWh)
HV = coal higher heating value (Btu/lb)

Annual coal use is then calculated by multiplying by the plant (or unit) capacity factor, which is determined by the dispatching module.

5.2.2.2 **Flue Gas Flow Rate**. Because the flue gas flow rate is a factor in several of the cost models, a convenient means of estimating its value is desirable. The following analysis by Molburg [1] suggests a procedure for estimating the flue gas flow rate from a minimum of information, since usually only heating value, ash, and sulfur content are known.

The components of coal on a dry, ash-free basis are carbon, hydrogen, nitrogen, sulfur, and oxygen. The theoretical number of pound-moles of combustion gas (CG) produced per pound of moisture-and-ash-free coal (MAF) with complete combustion is:

$$CG = \frac{C}{12} + \frac{H}{2} + \frac{N}{28} + \frac{S}{32} \qquad \text{[Eq 4]}$$

where C, H, N, and S are weight fractions of carbon, hydrogen, nitrogen and sulfur, respectively, and CG is pound-moles of combustion gas.

The relationship between the constituents of typical coals is such that this theoretical combustion gas production is linearly related to the coal heating value. An ordinary least squares regression on data for 75 sample coals [1], including lignitic through low-volatile bituminous coals, has been performed. It suggests the following relationship between heating value (Btu/lb MAF coal) and the indicated combustion gas production (lb-moles/lb MAF coal):

$$CG = 4.18 * 10^{-6} * HV_{MAF} + 0.036 \qquad [Eq\ 5]$$

where HV_{MAF} is the heating value of the MAF coal in Btu/lb.

The total flue gas (FG) includes this combustion gas and the constituents of the theoretical and excess air plus water from moisture in the coal.

It is convenient to express this on a pound-mole per pound MAF coal basis as:

$$FG = CG + O_2\,(excess) + N_2\,(total) + H_2O(air) + H_2O\,(coal) \qquad [Eq\ 6]$$

where CG is as defined in Equation 5. The excess oxygen is defined as a function of the theoretical oxygen.

The theoretical oxygen requirement in moles of oxygen is[3]

$$O_{(th)} = (44\,\frac{C}{12} + 64\,\frac{S}{32} + 18\,\frac{H}{2} + 28\,\frac{N}{28} - 1)/32\ . \qquad [Eq\ 7]$$

An ordinary least squares regression of this on the same coal data indicates the following relationship:

$$O_2 = 5.69 * 10^{-6} * HV_{MAF} - 0.003\ . \qquad [Eq\ 8]$$

If 100 percent excess air is supplied,

$$O_2\,(excess) = e * O_2 \qquad [Eq\ 9]$$

where e is excess air (mass fraction).

The nitrogen that accompanies the total oxygen from air is

$$N_2\,(total) = \frac{79}{21} * (1 + e) * O_2\ . \qquad [Eq\ 10]$$

The water from the air supply is

$$H_2O\,(air) = \frac{W}{18} * [28 * N_2\,(total) + 32 * (1 + e) * O_2\,] \qquad [Eq\ 11]$$

where W is the weight fraction of moisture in the air.

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[3] The total weight of oxides formed from one pound of MAF coal minus 1 (one pound) must be the weight of oxygen required in addition to that inherent in the coal.

Substituting from Equation 11, we obtain

$$H_2O\ (air) = 7.63 * W * O_2\ (1 + e). \qquad \text{[Eq 12]}$$

The water in the coal on a pound-mole per pound MAF coal basis is defined as

$$H_2O\ (coal) = \frac{\%m}{18\ (100 - \%A - \%m)} \qquad \text{[Eq 13]}$$

where $\%m$ and $\%A$ are percent coal moisture and percent ash on an as-fired basis, respectively. Substituting Equations 5, 8, 9, 12, and 13 into Equation 6 gives:

$$FG = 4.18 * 10^{-6} * HV_{MAF} + 0.036 + [3.76 + 4.76 * e + 7.63 * W * (1 + e)] * O_2 + \frac{\%m}{18\ (100 - \%A - \%m)} \qquad \text{[Eq 14]}$$

Substituting Equation 8 into Equation 14 and dividing through by HV_{MAF}, we can obtain the total flue gas on a pound-mole per Btu MAF coal basis:

$$\overline{FG} = 4.18 * 10^{-6} + \frac{0.036}{HV_{MAF}} + [3.76 + 4.76e + 7.63W * (1 + e)] * (5.69 * 10^{-6} - \frac{0.003}{HV_{MAF}}) + \frac{\%m}{18 * (100 - \%A - \%m)} * HV_{MAF}. \qquad \text{[Eq 15]}$$

Coal heating value on an MAF basis is related to heating value on an as-fired basis (HV) by

$$HV_{MAF} = \frac{100 * HV}{100 - \%A - \%m}. \qquad \text{[Eq 16]}$$

Therefore, knowledge of the heating value, the percent ash, and the percent moisture in the as-fired coal is sufficient to estimate the flue gas flow rate if the excess air is known, as well as the weight fraction of moisture in air. The latter is not a significant factor, and may be reasonably estimated to have a value of 0.01 [1]. Simplifying Equation 15,

$$\overline{FG}\ (lb\text{-}moles/Btu) = [2.601 + 2.752e + (24.5 - 14.5e) \frac{(100 - \%A - \%m)}{HV} + \frac{(55.6)(\%m)}{HV}]\ 10^{-5} \qquad \text{[Eq 17]}$$

Converting from moles per Btu to volume per Btu using the perfect gas law at a pressure of one atmosphere and then multiplying by the plant size and heat rate gives the flue gas volumetric flow rate, G. In units or actual cubic feet per minute (acfm), this is:

$$G = (MW)(HR)(T/760) * \{0.240 + 0.254e + [(2.265-1.341e)(100-\%A-\%m) + (5.140)(\%m)]/HV\} \qquad \text{[Eq 18]}$$

where G = gas flow rate (acfm)

MW = gross plant size

HR = gross cycle heat rate (Btu/KWh)

e = total excess air (mass fraction)

T = gas temperature ($^{\circ}$R, where $^{\circ}\mathrm{R} = {}^{\circ}\mathrm{F} + 460$)

$\%A$ = percent ash in as-fired coal

$\%m$ = percent moisture in as-fired coal

HV = coal heating value, as fired (Btu/lb)

This is the expression used in the AUSM to calculate the gas flow rate used in the economic models.[4] Since coal moisture content is not available in the AUSM data base, nominal values are assumed based on typical U.S. coal characteristics [37-40], as follows:

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[4] It should be noted that additional simplification of Equation 18 also can be obtained using characteristic properties of coals. Molburg [1] indicates that use of HF_{MAF} = 13,500 Btu/lb, HV = 11,000 Btu/lb, and m = 0.10 will not cause more than a few percentage points error for most U.S. coals. This leads to a simple expression based only on plant size, heat rate, excess air and gas temperature:

$$G = MW * HR * (0.262 + 0.243 * e) * (T/760) \qquad \text{[Eq 18a]}$$

For a typical power plant with values of e at 0.35 (including leakage) and T at 760°R (300°F), this further reduces to

$$G = 0.347 * MW * HR, \qquad \text{[Eq 18b]}$$

which may be useful for approximate analysis in some applications.

Coal Type	*Percent Moisture*
Bituminous	10
Sub-bituminous	25
Lignite	35

The AUSM method of classifying coals by rank is discussed in Section 5.3.

5.2.2.3 **Flyash Removal and Emission Rates**. Particulate emissions from oil- and as-fired boilers are calculated with emission factors developed by EPA [4]. The emissions are based on annual fuel consumption, which is calculated in the dispatching module.

The total suspended particulate (*TSP*) removal rate for coal-fired boilers is specified by

$$A = \dot{M}_{coal} * \frac{\%A}{100} * f_o^a * \eta_{TSP} \qquad \text{[Eq 19]}$$

where A = TSP removal rate

$\%A$ = percent ash in coal

$\dot{M}_{coal}$ = coal mass input rate (Equation 3)

η_{TSP} = fraction TSP removal by control device

f_o^a =fraction of coal ash to overhead

and A is in tons per hour, the same units as the coal mass flow rate.

When an emission constraint (EC_a) is specified in pounds per million Btu, as are the New Source Performance Standards (NSPS), η_{TSP} needed for Equation 19 is calculated using a simple mass balance:

$$\eta_{TSP} = 1.0 - \frac{EC_a * HV}{\%A * f_o^a * 10^4} . \qquad \text{[Eq 20]}$$

5.2.2.4 **Sulfur Dioxide Removal and Emission Rates**. Sulfur dioxide emissions for oil- and as-fired boilers are calculated using EPA emission factors [4]. Values appear in Section 5.3. Emissions from coal-fired boilers are assumed to be at the level of the applicable standard (State Implementation Plan, New Source Performance, or Revised New Source Performance).

The New Source Performance Standards for units commencing construction between August 17, 1971, and September 18, 1979, limit maximum SO_2 emissions to 1.2 pounds per million Btu heat input to the boiler. The Revised NSPS (RNSPS) express the allowed SO_2 emissions as a percentage of emissions that would result from uncontrolled combustion of the run-of-mine coal (i.e., the "potential" SO_2 emissions). If these potential emissions are expressed in pounds per million Btu, the fraction of emissions allowed can be determined directly in these units. For coal of heating value HV_{rom} and weight fraction sulfur S_{rom}, the potential SO_2 emission rate is

$$Potential\ SO_2\ (lb/10^6 Btu) = 2 * 10^6\ S_{rom}/HV_{rom}. \qquad [Eq\ 21]$$

The allowable SO_2 emission rate, EC_s, is

$$EC_s = 2 * 10^6 * S_{rom}(1 - r)/HV_{rom} \qquad [Eq\ 22]$$

where r is the required fraction reduction of potential emissions.

Alternatively, if an SO_2 emission constraint (ECs) is specified in units of pounds per million Btu, the required SO_2 removal efficiency (η_{SO_2}) for a flue gas desulfurization system would be given by

$$\eta_{SO_2} = 1 - \frac{EC_s * HV}{2\, f_s * \%S * 10^4} \qquad [Eq\ 23]$$

where $\%S$ is the percentage of sulfur in delivered coal and f_s is the fraction of sulfur in the feed coal that enters the flue gas (the fraction of sulfur overhead). This fraction is estimated for different boiler types using EPA emission factors [4]. The uncontrolled SO_2 emission rate, ER_s, then would be

$$ER_s(lb/10^6\ Btu) = 2 * 10^4 * f_s * \%S/HV. \qquad [Eq\ 24]$$

The rate of coal consumption in million Btu per hour at maximum capacity is $HR * MW/10^3$, where HR is the gross cycle heat rate and MW is the gross plant capacity. The SO_2 removal rate required to reduce emission rate to an allowable level is

$$S = (ER_s - EC_s) * HR * MW/2 * 10^6 \qquad [Eq\ 25]$$

where S = overall SO_2 removal rate (tons/hr)

ER_s = uncontrolled emission rate (given by Equation 24)

EC_s = allowable emission rate (given by Equation 22 or is some specified allowable emission rate in $lb/10^6$ Btu).

5.2.2.5 **FGD System Bypass.** Under certain circumstances, it may be possible to achieve air pollutant emission standards by desulfurizing only a portion of the flue gas. This is possible when a particulate collector meeting the TSP emission standard is located upstream of the flue gas desulfurization (FGD) system (the nominal configuration assumed for the AUSM) and when the SO_2 emission standard permits an overall SO_2 removal efficiency less than the maximum achievable by a scrubber or other removal device. This situation applies to most plants constructed before 1979, which are not subject to the Revised New Source Performance Standards.

Let η_{SO_2} be the overall required SO_2 removal efficiency (i.e., as calculated from Equation 23), and let η_{FGD} be the efficiency of SO_2 removal for a scrubber treating only part of the flue gas ($\eta_{FGD} > \eta_{SO_2}$). Assuming that the treated and untreated gas streams are completely mixed to determine the overall emissions, it can be shown that the fraction of gas that can be bypassed is

$$f_{byp} = 1 - \frac{\eta_{SO_2}}{\eta_{FGD}} . \qquad \text{[Eq 26]}$$

In the AUSM, it is assumed that, practically, a bypass system would not be constructed unless sufficient flue gas could be bypassed to warrant the incremental expense and trouble. The criterion selected is one based on equivalent power plant capacity, with a default value of at least 60 megawatts of bypass before that option is implemented.

5.2.2.6 **Nitrogen Dioxide Emission Rates.** Nitrogen dioxide emission rates for coal, oil, and gas units subject to State Implementation Plan (SIP) emission standards are calculated with EPA emission factors [4]. Units subject to a New Source Performance Standard are assumed to emit at the appropriate NSPS level. All numerical values appear in Section 5.2.3.

5.2.3 Economic and Performance Models for Nitrogen Oxide Control

5.2.3.1 NO_x Emissions from Utility Boilers. Nitrogen oxides (NO_x) are formed during combustion by reactions between oxygen and nitrogen at elevated temperatures. For coal-fired boilers about 95 percent of NO_x is emitted as nitric oxide (NO) and the remainder as nitrogen dioxide (NO_2). For coal-fired boilers it has also been estimated that 80 percent of the NO_x is from fuel-bound nitrogen and that the remaining 20 percent is "thermal" NO_x based on nitrogen in air [48].

Baseline NO_x emission data are relatively limited, but show large variations with fuel type, firing method and unit size, as illustrated in Table 5-2 for coal-fired units. Estimates of uncontrolled NO_x emis-

Table 5-2
NO_x EMISSIONS FROM COAL-FIRED UTILITY BOILERS[a]

Size Range	Coal Firing Method	NO_x (ppm)[b]
200-400	Single wall-dry bottom	600-800
200-400	Single wall-wet bottom	900-1400
200-400	Horizontal Opposed Wall	400-1000
200-800	Tangential	400
200-800	Cyclone	800-1500

[a] *Reference [48].*

[b] *Based on bituminous coal fired at 120 percent excess air, 400 ppm is equivalent to 0.68 lb $NO_x/10^6$ Btu.*

sions are based on representative "emission factors" published by the U.S. Environmental Protection Agency (EPA) [4]. These are summarized in Table 5-3, along with New Source Performance Standard (NSPS) levels for fossil fuel power plants. Boiler firing types in the AUSM data base are summarized in Table 5-4. Coal-fired units constitute five times the capacity of either oil or as-fired units. The largest category among known firing types is tangential while the smallest are cyclone and wet-wall fired. This is beneficial from the modeling standpoint since tangential units are better represented by a single emission factor than cyclone or wet-wall fired units.

5.2.3.2 **NO_x Control Alternatives.** Reduction of NO_x emissions in new or existing units in principle may be achieved through combustion modifications and/or flue gas treatment (FGT) technology [48-58]. In practice, FGT systems achieving high (80 percent or more) levels of NO_x removal have not yet been commercially demonstrated in the United States,[5] and are not widely regarded as a near-term option for NO_x control. Their high cost also precludes their likely consideration under current regulatory requirements. Combustion modification techniques, on the other hand, may be capable of reducing NO_x emissions by up to about 60 percent, and are the principal methods currently being considered for NO_x control. Such techniques have already been widely implemented on new fossil fuel boilers, and also—though to a much lesser extent—on existing units. Retrofit applications lie primarily with oil and as-fired units; relatively little has been experienced with coal-fired facilities [54].

Combustion modifications currently in use are based primarily on lowering the oxygen content in the primary flame zone and, secondarily, on lowering peak flame temperature.

There are four general control methods:

1. Low excess air (LEA)
2. Flue gas recirculation (FGR)
3. Low NO_x Burners (LNB)
4. Off-stoichiometric combustion (OSC), also known as staged combustion. OSC may consist of:
   (a) biased firing

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[5] Such systems, however, are functioning commercially in Japan.

Table 5-3

NO_x EMISSION FACTORS FOR FOSSIL-FUEL FIRED BOILERS

Source Category	Coal	Oil	Gas
General:[a]	*(lb/ton)*	*(lb/1000 gal)*	*(lb/10^6 SCF)*
Tangential	15	67 (106)[b]	550
Dry bottom	21	42	275
Wet bottom	34		
Cyclone	37		
Spreader stoker	14		
Lignite:[a]			
Dry bottom	12		
Tangential	8		
Wall	14		
Cyclone	17		
Spreader stoker	6		
New Source Performance Standards[c]			lb $NO_2/10^6$ Btu
(a) Construction after Aug. 17, 1971	0.7 0.6[d]	0.3	0.2
(b) Construction after Sept. 18, 1978	0.8 0.6[f] 0.5[g] 0.8[h]	0.3	0.2

---

[a] *Reference [4].*

[b] *Use 67 for general boilers and 105 for vertical fired boilers.*

[c] *Reference [58].*

[d] *Lignites.*

[e] *Lignite from ND, SD, MT burned in cyclone-fired units.*

[f] *Bituminous, lignite and anthracite.*

[g] *Sub-bituminous, coal-derived fuels, shale oil.*

[h] *>25% lignite from ND, SD, MT burned in slag tap furnace.*

Table 5-4

1980 AUSM UNIT INVENTORY BOILER BREAKDOWN

(As of August 11, 1982, Test Version 1.5)

Firing Method	Coal[a]		Residual Oil		Distillate Oil[b]		Natural Gas -		Nuclear		ydro/Geothermal[c]	
	MW	# Units	MW	# Units	MW	# Units	MW	# Units	MW	# Units	MW	# Units
Single Wall[d]	41,337	330	24,696	188	-	-	27,760	286	-	-	-	-
Opposed	56,189	108	13,831	44	-	-	29,084	87	-	-	-	-
Tangential	100,723	372	24,176	108	-	-	20,100	101	-	-	-	-
Stoker	155	4	0	0	-	-	-	-	-	-	-	-
Cyclone	21,114	78	2,120	15	-	-	678	2	-	-	-	-
Unknown	178,321[e]	589	4,146	45	26,470	353	8,821	120	-	-	-	-
Total[f]	397,839	1481	68,969	400	26,470	353	86,443	569	148,971	157	79,664	661
Percent Total	49.2	40.6	8.5	11.0	3.3	9.7	10.7	16.3	18.4	4.3	9.8	18.1

[a] FGD Total = 18,187 MW limestone.

[b] Peaking combustion turbine 16,703 MW; intermediate combined cycle 786 MW; peaking residual turbine 7102 MW; residual combined cycle 189 MW.

[c] Hydroelectric 75,172 MW (588 units); geothermal 1654 MW (20 units); unknown 2818 MW (53 units).

[d] Composed of wet bottom 37,623 MW (157 units) and dry bottom 177,000 MW (724 units).

[e] 139,000 MW applies to plants planned or under construction.

[f] Total all units 808,336 MW, 3648 units; includes planned units - 277,321 MW (554 units).

(b) burners out of service (BOOS)

(c) over-fire air (OFA)

Each of these control methods is briefly discussed below.

Low Excess Air (LEA). Excess air is a surrogate measure for excess oxygen which is what a plant operator measures and tries to maintain at a specified level. Modern boilers generally operate at 3 to 4 percent excess O_2. A typical excess air level is 20 percent, equivalent to 3.5 to 4.0 percent excess O_2 (depending on fuel oxygen). LEA is typically defined as a 1 percent decrease in O_2, which corresponds to a decrease of 5.0 to 5.7 percent in excess air. Older boilers may operate at 5 to 6 percent excess O_2 and thus can more easily operate at low excess air. Limited tests show about 100 ppm (15 percent) NO reduction per 1 percent O_2 reduction for wall-fired units and 10 percent reduction for tangential fired units [56]. LEA is not recommended for cyclone units due to corrosion problems [48]. For coal-fired units, problems with LEA include smoking, slagging, and excess char carryover (incomplete combustion) resulting in thermal efficiency losses. These are balanced against efficiency gains due to decreased stack heat losses.

Flue Gas Recirculation (FGR). Here, about 15 percent of the flue gas is recycled to the secondary air input. Reduced NO_x emissions result from lower O_2 (due to dilution with the combustion byproducts) and lower peak flame temperature (due to the presence of heat-absorbing combustion products).

Little data on FGR is available, however; only one full-scale coal-fired utility application had been reported as of 1980 [48]. Its effectiveness had a maximum of 20 percent NO_x reduction, and decreased as excess air decreased. FGR could be expected to lower downstream air flow, as with LEA.

Biased Firing: Biased firing consists of decreasing fuel or increasing air to upper burners. The result is to decrease O_2 at the lower burners and increase it at the upper ones. This is the least effective OSC method; NO_x reduction potential ranges from 5 to 7 percent [48].

Burners Out of Service (BOOS). Fuel flow to selected burners is stopped while the air flow continues. To maintain output, flue flow to the other burners must be increased by a like amount. At coal-fired plants this may not be possible due to coal pulverizer and nozzle flow limitations, thus requiring derating of the boiler. Successful BOOS can yield NO_x reductions of 25 to 45 percent [48].

Overfire Air (OFS). New air ports are installed above the burner region and receive about 20 percent of the total combustion air. Total air flow will increase slightly. It is easier to do this on a new boiler than on an existing one because of space limitations. NO_x reduction potentials range from 30 to 40 percent for tangential units to 30 to 50 percent for wall-fired units [51].

Low-NO_x Burners (LNB). Low-NO_x burners represent perhaps the most promising option for NO_x emission control. These have been utilized on new units as well as retrofit applications. For coal-fired units, concern has been expressed about the use of LNB with low sulfur coals ($\leq$2 percent) because of furnace-wall corrosion problems [50]. When feasible, LNB offer the highest consistent degree of NO_x control. Emission reductions range from 40 to 60 percent for coal-fired boilers [51].

Combinations of Controls. The most widely used combination is low-NO_x burners and overfire air. Here, overfire air increased one coal-fired low-NO_x burner removal efficiency by 25 percent and another by 16 percent [49,50]. There is little experience with combining the other methods, though what data there are show that reduction effects are not additive.

5.2.3.3 **Cost and Performance Models.** The NO_x control options adopted for the AUSM consist of low-NO_x burners and overfire air, which appear to be the most viable and widespread options for coal-fired plants. Overfire air with flue gas recirculation is also considered for oil and as-fired units. Low excess air was not included as an option because the potential reduction (of about 10 percent) is small compared to variations in baseline data (up to a factor of two) [51].

Because the level of NO_x reductions achievable through combustion modifications is not extremely well-defined (and often quite site-specific), the performance model adopted for the AUSM is a simple percent reduction of uncontrolled emissions for a given combination of boiler type and control method. Values are summarized in Table 5-5 and are based on the results of recent studies, particularly the extensive work by Acurex Corporation for the EPA [51,52,57]. The performance of low-NO_x burners for new and retrofit tangentially fired boilers (not yet prevalent in power plants in the United States) is based on a feasibility study by Combustion Engineering, which has the U.S. license for the Mitsubishi Heavy Industries Low-NO_x PM Burner system developed in Japan [55].

Economic models also are summarized in Table 5-5 and are based on studies by Acurex and Combustion Engineering [51,52,55,57]. Total capital and operating costs are proportional to plant size for large units (above 250 MW), and exhibit an exponential dependence on size for smaller units. The range of capital costs provided by these equations is shown in Figure 5-1. Total capital costs for NO_x controls are quite small compared to other pollution control costs (e.g., about 5 percent of the cost of an FGD system). Operating costs also often are negligible, though small operating costs may be incurred because of the need for additional combustion controls and increased maintenance. Similarly, a small energy penalty also is incurred with overfire air because of the increased fan load due to additional duct work.

5.2.4 Economic and Performance Models for Electrostatic Precipitators

5.2.4.1 **Overview.** Dry collection of flyash is assumed to be achieved using either an electrostatic precipitator (ESP) or a fabric filter. Various studies suggest that the flange-to-flange capital cost of both types of devices scales principally with the physical collection area. This is the chief parameter in the models. A second term, dependent on plant capacity, reflects the added cost of ash-handling equipment.

For electrostatic precipitators, the capital costs were adopted from Research-Cottrell results [5], which are in substantial agreement with other results [6,7]. The total collection area of the precipitator is the product of the flue-gas volumetric flow rate, G, and the specific collection area (SCA). The former can be calculated using coal and plant data, as discussed in Section 5.2.2.2. SCA depends on the required particulate removal efficiency and the particle drift velocity. The latter is nearly constant for a hot precipitator and is related to coal sulfur content for a cold precipitator [6,8]. The required removal efficiency is determined principally by the particulate emission constraint and the coal ash content (see Section 5.2.2.3). Thus, the capital cost model is sensitive both to coal properties and environmental regulations.

The model of total variable cost for precipitators shows that these can also be represented as a function of collector area. Electric power costs are accounted for separately. Power requirements are expressed in megawatts, to which a unit cost of electricity is then applied.

The models selected here are believed to be appropriate to the level of site-specific information available in the AUSM data base. While the lack of detailed information on coal characteristics precludes

Table 5-5

ECONOMIC AND PERFORMANCE MODELS FOR NO_x CONTROLS[a]

Boiler and Fuel Type	Control Measures	Boiler Firing Method	% NO_x Reduction[b]	Total Capital Cost (1981 $)		Total Variable[c] Costs (1981 $)	Energy Penalty (% MW)
				MW < 250	MW ≥ 250		
New Boilers							
Coal	Low-NO_x	Tangential[d]	50	$76,527 * MW^{0.5}$	4840 * MW	nil	0
	Burners	Wall	50	$49,440 * MW^{0.5}$	3127 * MW	nil	0
Retrofit Boilers							
Coal	Overfire air	Tangential	35	$18,095 * MW^{0.5}$	1144 * MW	31.7 * MW * CF	0.11%
		Wall	40	$13,204 * MW^{0.5}$	835.1 * MW	23.2 * MW * CF	0.11%
	Low-NO_x	Tangential[d]	40	$153,054 * MW^{0.5}$	9860 * MW	nil	0
	Burners	Wall	40	$67,059 * MW^{0.5}$	4241 * MW	132 * MW * CF	0
Oil or	Overfire air +	Tangential or	45	$75,402 * MW^{0.5}$	4769 * MW	232 * MW * CF	0.81%
Gas	Flue Gas Recirc.	Wall	65				

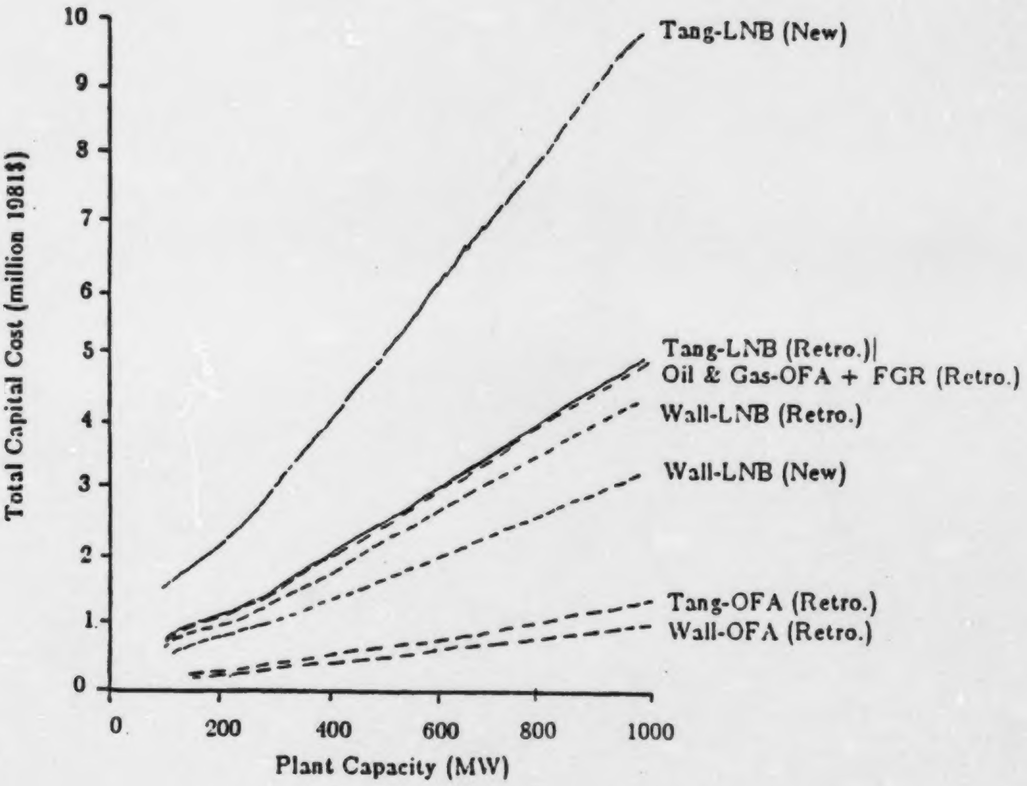
[a] Reference [51]. Costs may vary by a factor of 2 due to site-specific parameters. This cost does not include interest during construction

[b] These numbers are midpoints within ranges of ± 15% - 25%, depending on techology.

[c] Variable costs are for additional maintenance.

[d] Calculated from Reference [56].

Figure 5-1
TOTAL CAPITAL COSTS OF NO_x CONTROL



the use of more detailed ESP models to estimate SCA, this limitation is not significant in most cases. Only where a cold-side ESP is considered for use with a low-sulfur coal have data base limitations required simplifying assumptions to reflect actual utility practice in the sizing of an ESP. In general, model assumptions made for ESP collectors are comparable to those made for fabric filter devices.

5.2.4.2 **Details of Physical/Performance Models.** The essential factor affecting efficiency and cost of an electrostatic precipitator is the specific collection area, expressed as square feet of collector area per acfm gas flow. Deutsch [9] has derived an equation relating specific collection area, efficiency, and particle drift velocity:

$$\eta = 1 - exp(-\upsilon * SCA) \qquad \text{[Eq 27]}$$

where η = precipitator efficiency (weight fraction of flyash removed from flue gas stream)

SCA = specific collection area (ft^2/acfm)

υ = migration velocity (ft/min)

The Deutsch equation assumes complete turbulence, constant bulk velocity, homogeneity and isotropy of turbulence, uniform particle distribution, and constant migration velocity. While these conditions are obviously unrealistic, certain empirical adjustments to the original Deutsch equation result in an equation that very nearly predicts the relationship between observed values of efficiency, migration velocity, and SCA. The form typically used is

$$\eta = 1 - \exp[-(w * SCA)^k] \qquad \text{[Eq 28]}$$

where k = constant, from 0.4 to 0.7

η = overall collection efficiency (fraction)

SCA = specific collection area (ft^2/acfm)

w = modified migration velocity (ft/min)

The equation adopted here is similar, and is due to Farber [10], whose recent analysis draws upon many of the important earlier works in this field:

$$\eta = 1 - \exp\left[-1.042 * (w * SCA)^{0.6464}\right] \qquad \text{[Eq 29]}$$

or

$$SCA = \frac{0.938}{w} * \left[-ln(1 - \eta)\right]^{1.549}. \qquad \text{[Eq 30]}$$

If reasonable electric field strength and particle diameter distributions are assumed, the migration velocity w may be expressed as a function of flyash resistivity. This has been done by Farber [10] based on published data. His result is

$$w = 38.474 \;/\; [6.396\ 10^{-10}\ exp(1.382 * lnR) + 1] \qquad \text{[Eq 31]}$$

where w = modified migration velocity (ft/min)

R = flyash resistivity (ohm-cm)

Resistivity, in turn, is a function of particle composition. It is very dependent on sulfur content, decreasing as the sulfur content increases. The correlation used here is also due to Farber and is based on published data. It applies at about 300°F, the normal operating temperature for a cold electrostatic precipitator:

$$lnR = (6.98 - 1.36\%S) * exp(-0.02075 * \%S^{1.2158}) + 20.723 \qquad \text{[Eq 32]}$$

This equation is supported by the results of Bickelhaupt [11], who has measured the resistivity of flyash as a function of SO_3 concentration in the flue gas. SO_3 is the sulfur-containing specie that affects resistivity. Since about 1 percent of total sulfur is converted to SO_3, Bickelhaupt's results can be expressed as a function of the weight percent sulfur. The laboratory results for an eastern coal are close to Equation 29.

Knowing the required flyash removal efficiency (see Section 5.2.2.3), Equation 30 can be used to determine SCA, where, for a cold ESP, w is determined according to Equations 27 and 28. As shown in Figure 5-2, calculated SCA generally lies between results for two alternative models developed by other investigators [14,15]. One is the model developed by Teknekron Research, Inc. (TRI) and incorporated in its Utility Simulation Model (USM) developed for the U.S. Environmental Protection Agency [15]. The other model, developed by PEDCo Environmental, Inc., also was adopted by EPA for studies of flyash control on industrial boilers [14]. The model adopted here has been developed more recently and

Figure 5-2a

SCA VERSUS TSP REMOVAL EFFICIENCY

(sulfur content at 1.5 percent)

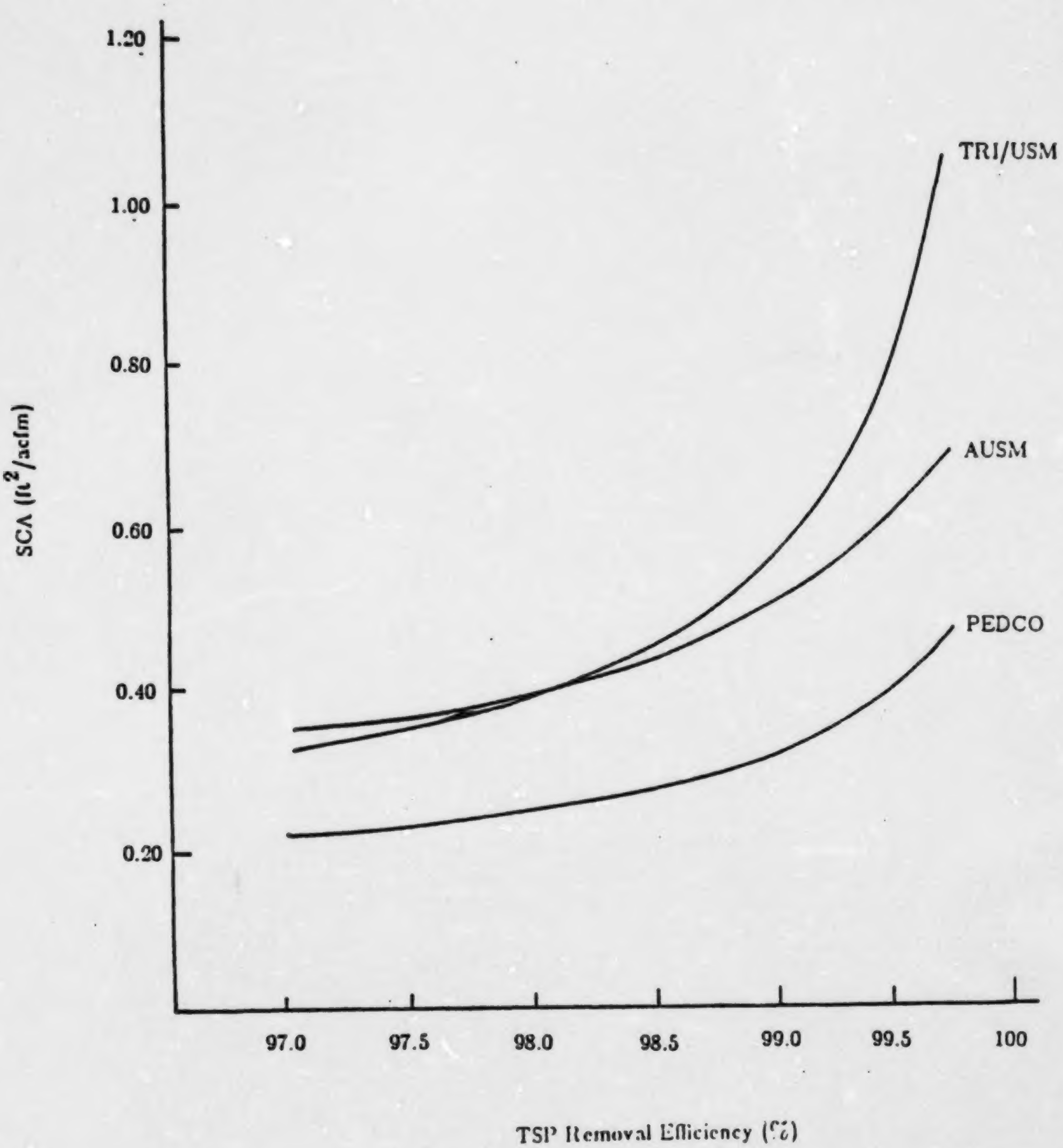


Figure 5-2b
(Sulfur content at 2 percent)

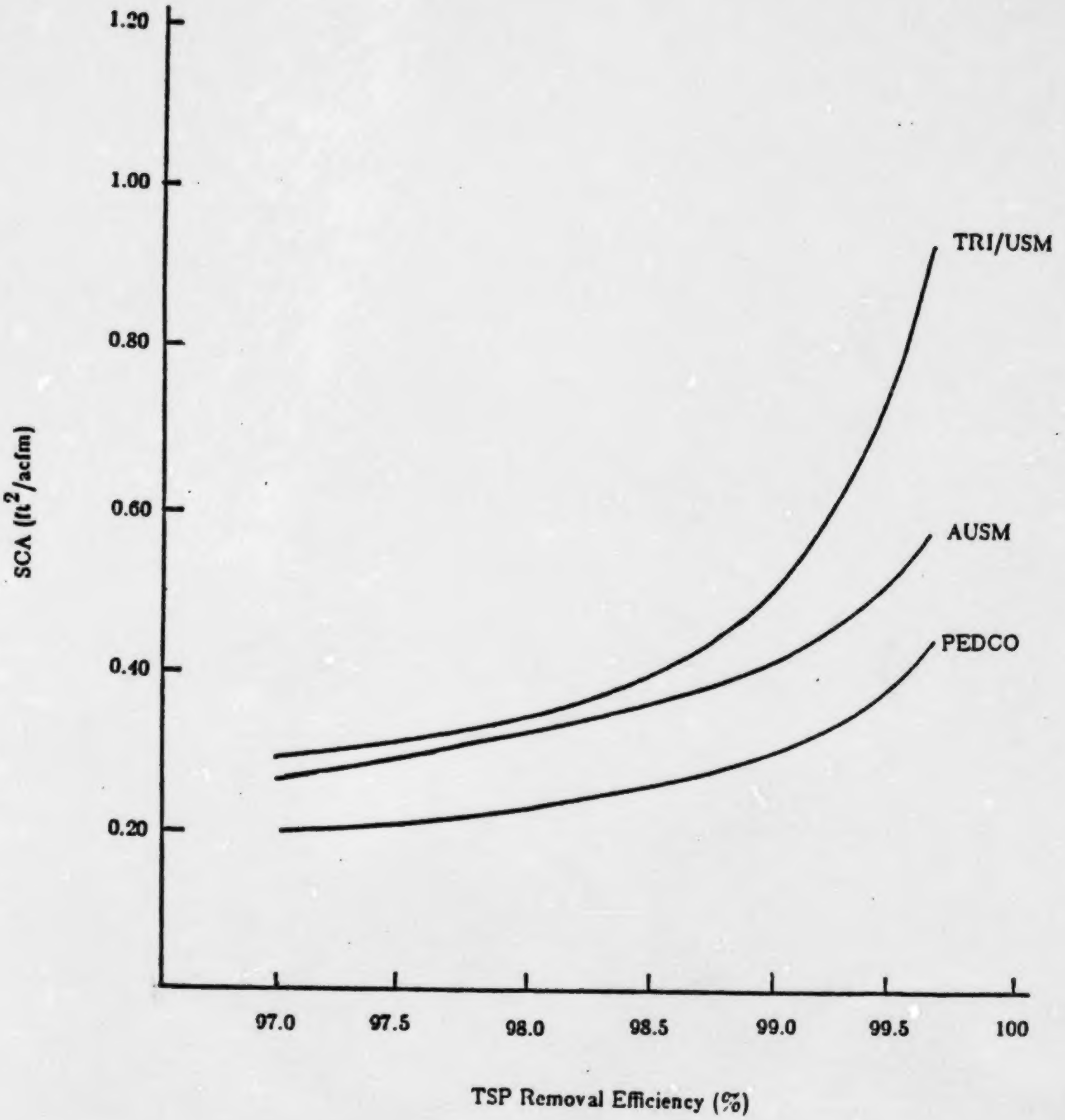
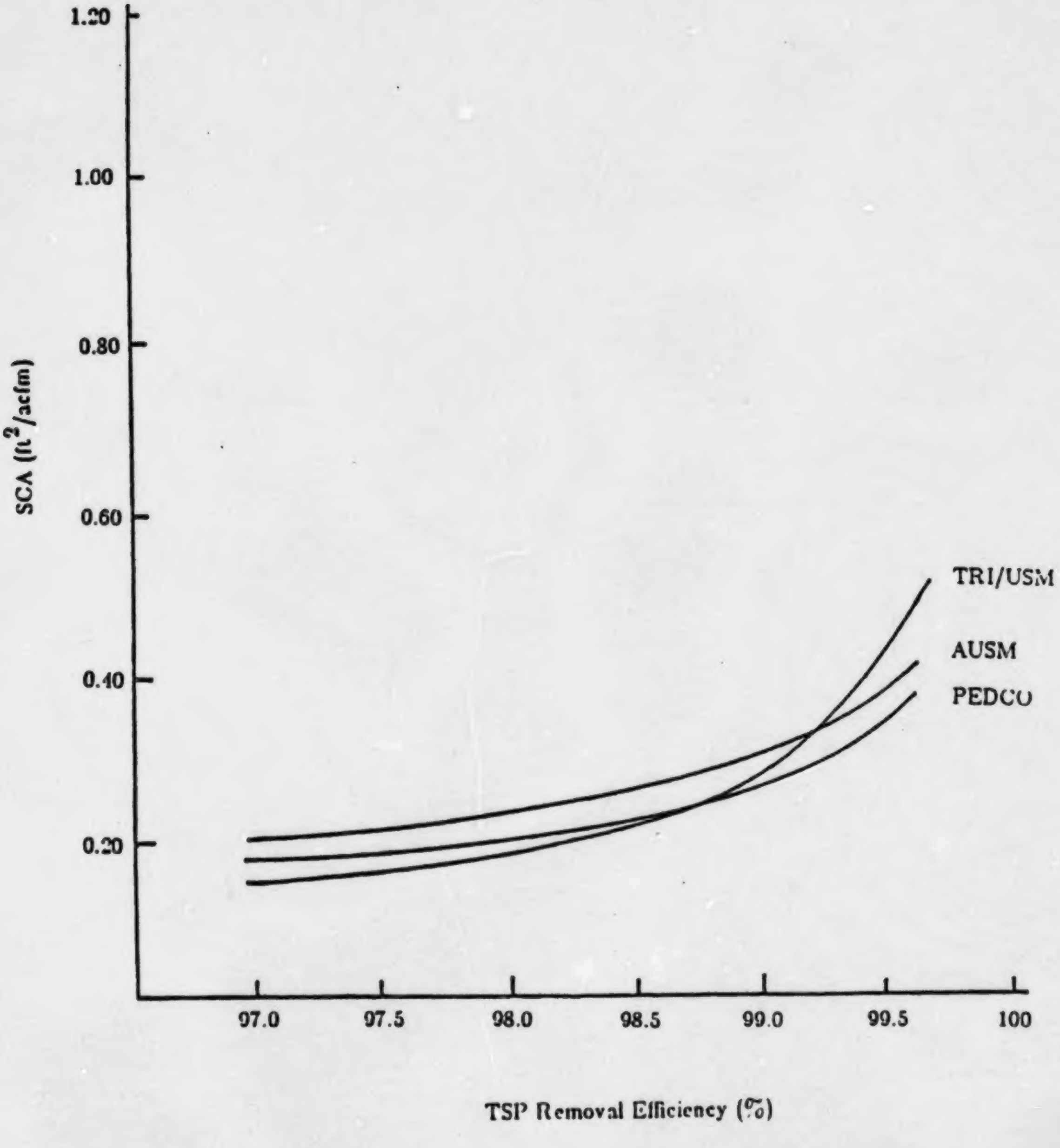


Figure 5-2c

(Sulfur content at 3 percent)



represents an intermediate case between these two earlier models.

As noted, the performance model described earlier does not apply to low-sulfur coals. Combustion of low-sulfur coal results in high resistivity ash, which has poor charging characteristics. Consequently, precipitation of low-sulfur ash is difficult. The problem may be overcome by use of a hot-side ESP, which operates at temperatures of 600°F to 800°F, a range where resistivity is low even for low-sulfur coal ash. The problems of hot ESPs include increased complexity of construction due to insulation requirements, warping or expansion hazards, and increased gas volume leading to substantially higher collection areas and costs. About 100 hot-side ESPs have been installed at U.S. power plants using low-sulfur coals. However, there have been no new installations or new orders in several years. This appears to be related to operating and warranty difficulties on several of the recent installations. Thus, in recent years there has been growing interest in the use of cold-side ESPs for low-sulfur coal applications.

Cold-side ESPs can be designed to handle ash from low-sulfur coals, but again at substantially higher collection areas (and costs) than for medium- and high-sulfur coal applications, which are by far more common. Recent experience shows that the performance of a cold-side ESP on low-sulfur coals also is affected significantly by the moisture content and ash alkali composition of the specific coal. However, neither of these properties is available in the AUSM coal data base.

A number of alternative models are being examined to characterize the performance of a cold-side ESP using low-sulfur coals. The current version of the AUSM assumes that Equation 32 continues to apply, with the drift velocity held constant at 20 feet per minute. This yields specific collection areas of approximately 700 ± 50 ft^2/1000 acfm for typical flyash removal efficiencies. Such values are consistent with current designs of cold ESPs for low-sulfur coal applications [6,16].

The model of a hot ESP also was based on recent utility experience reported in the literature. The average SCA for a group of hot ESP installations (reported in Reference 12) is 308 square feet per 1000 acfm, with a sample standard deviation of 41 square feet per 1000 acfm. For the same group of plants, the average migration velocity calculated from the simple Deutsch equation is 17 feet per minute, with a sample standard deviation of 1.3 feet per minute. Thus, drift velocity for a hot ESP appears to be nearly constant, although the value 17 feet per minute is inappropriate because of limitations of the Deutsch equation noted earlier. Data from sources that include hot ESP drift velocities [12,13] give a broader range of 16 to 34 feet per minute, as well as some drift velocities that imply uncharacteristically low SCA. Since the purpose of the AUSM is primarily to predict costs, a cost-based calibration has been applied to estimate a value of w that yields hot ESP costs relative to cold ESP costs that are consistent with current experience. The selected drift velocity is a constant value of 20 feet per minute, which is used in Equation 30 to estimate SCA.

5.2.4.3 **Capital Cost Models**. Precipitator size is expected to be the primary determinant of capital cost. A convenient indicator of size is total collection area, suggesting the following cost model:

$$\textit{capital cost} = k(AREA)^b \qquad \text{[Eq 33]}$$

where k and b are constants and $AREA$ is total collection electrode surface area, which is the product of SCA and the flue gas flow rate capacity.

As indicated, it is desirable to have simple models that are sensitive to emission constraints, coal characteristics, and significant technology characteristics. The required efficiency is determined by the flyash emission constraint and coal ash content and is related to collector area by the modified Deutsch equation. Also, for a cold ESP, area is related to coal sulfur content through sulfur's effect on migration velocity. Therefore, the model of Equation 33 is consistent with the AUSM needs.

5.2.4.3.1 **Cold-Side ESP Direct Cost**. Several models of this type have been examined [5,10,12,15]. Although the costs from these are comparable, only the Research-Cottrell model [5] isolates direct capital cost from total capital cost. The direct cost portions of that model include (in January 1977 dollars):

1. Complete collector (flange-to-flange) $= 18.0\ (\mathrm{AREA})^{0.89}$
2. Typical precipitator accessories, 15% of (1) $= 0.15\ (1)$
3. Structural support $= 0.99\ (\mathrm{AREA})^{0.97}$
4. Erection and installation $= 14.2\ (\mathrm{AREA})^{0.91}$

$$\textit{DCC, ash collection}\ (1977\$) = 20.7\ (AREA)^{0.89} + 0.99\ (AREA)^{0.97} + 14.2\ (AREA)^{0.91} \qquad \text{[Eq 34]}$$

It has been shown [18] that such an expression can be simplified to a single exponential term:

$$P = M_1P_1 + M_2P_2 + M_3P_3 \qquad \text{[Eq 35]}$$

where P_1, P_2, and P_3 are the exponents of the terms in Equation 34, and M_1, M_2, and M_3 are the fraction of total cost due to the corresponding terms.

Assuming a collection area of one million square feet (approximately that required for a 750 MW plant),

$$\begin{aligned} &\text{DCC, ash collection (1977\$)} \\ &= 20.7\ (10^6)^{0.89} + 0.99\ (10^6)^{0.97} + 14.2\ (10^6)^{0.91} \\ &= (4.53 + 0.862 + 4.10) * 10^6 \\ &= 9.49 * 10^6 \end{aligned} \qquad \text{[Eq 36]}$$

Thus,

$$M_1 = \frac{4.53}{9.49} = 0.477;\ M_2 = \frac{0.862}{9.49} = 0.091;\ M_3 = \frac{4.10}{9.49} = 0.432. \qquad \text{[Eq 37]}$$

Then, from Equation 36,

$$\begin{aligned} P &= 0.477\ (0.89) + 0.091\ (0.97) + 0.432\ (0.91) \\ &= 0.906. \end{aligned} \qquad \text{[Eq 38]}$$

This is the value of the exponent b in Equation 33. The coefficient k is then evaluated from the numerical example above. The resulting equation is

$$\mathit{DCC,\ ash\ collection}\ (1977\$) = 34.0\ (\mathit{AREA})^{0.91}. \qquad \text{[Eq 39]}$$

This cost does not include ash-handling equipment. For a cold ESP, the cost of these items in Reference 12 is about 43 percent of the flange-to-flange precipitator cost. For a 1000 megawatt plant, this is about $4.1 * 10^6$ 1977 dollars. Alternatively, based on itemized cost estimates for total power plants [19,20], the ash-handling equipment cost is about 4,400 1977 dollars per megawatt of plant capacity, or $\$4.4 * 10^6$ for a 1000 MW plant. This is in virtual agreement with the earlier figure. The direct capital cost model used here is based on this per megawatt charge:

$$DCC,\ ash\ handling\ (1977\$) = 4400 * MW \qquad \text{[Eq 40]}$$

where MW is the gross plant capacity in megawatts.

This model has the advantage of simplicity; it may be used for either fabric filters or hot or cold ESP. In general, the cost of ash-handling equipment would be expected to depend on the amount of ash removed, rather than on a technology-specific parameter such as collector area. The total direct capital cost (TDC), including ash handing, is

$$TDC,\ cold\ ESP\ (1977\$) = 34.0\ (AREA)^{0.91} + 4400 * MW \qquad \text{[Eq 41]}$$

Using the *Chemical Engineering* cost index [2]:

$$TDC,\ cold\ ESP\ (1981\$) = 49.64\ (AREA)^{0.91} + 6424 * MW \qquad \text{[Eq 42]}$$

5.2.4.3.2 **Hot-Side ESP Direct Cost**. The hot-ESP capital cost model is also based on Research-Cottrell estimates [5]:

(1) Complete collector, flange-to-flange $= 9.12\ (\text{AREA})^{0.95}$

(2) Typical precipitator accessories $= 0.15\ (1)$

(3) Structural support $= 0.58\ (\text{AREA})^{1.01}$

(4) Erection and installation $= 5.64\ (\text{AREA})^{0.98}$

From analysis similar to that used for the cold ESP, the sum of these items is approximated by

$$TDC,\ hot\ ESP\ (1981\$) = 22.56\ (AREA)^{0.97} \qquad \text{[Eq 43]}$$

Using the ash-handling system cost developed earlier, the total direct capital cost (TDC) for the hot ESP with ash handling is

$$TDC,\ hot\ ESP\ (1981\$) = 22.56\ (AREA)^{0.97} + 6424 * MW \qquad \text{[Eq 44]}$$

5.2.4.3.3 **Indirect Costs.** The direct cost models suggested earlier include the construction expense item normally given as an indirect cost. This item, therefore, should not be included in the indirect cost factor. Also, since precipitator technology is well-established, coupled with several decades of operating experience, a low contingency allowance of 5 percent probably is not unreasonable. Based on published studies, the nominal indirect cost factor is assumed to be 0.50, including interest during construction (AFUDC). To allow for consistent treatment of AFUDC in the AUSM, the nominal indirect cost factor is reduced to 0.36, with interest charges then explicitly added.

5.2.4.4 **Variable Cost Model, Excluding Utilities.** Precipitator variable costs include expenses for operation, maintenance, and power. Operating costs are not well-documented since no special account is kept for precipitator operation. Operating labor is negligible. Average maintenance costs for a representative group of utility installations is $55.6 per 1000 square feet per year (1977 basis) [21]. Maintenance and overhead are total precipitator variable costs that are charged explicitly. Assuming that overhead is 50 percent of maintenance and that there are no administrative costs, the total variable cost, excluding utilities, is

$$TVC,\ ESP\ (1981\$/yr) = 0.1213 * SCA * G * CF \qquad \text{[Eq 45]}$$

where $SCA =$ specific collection area (ft^2/acfm)

$G =$ gas flow rate capacity (acfm)

$CF =$ annual average capacity factor

Additional energy costs are calculated from the model that follows.

5.2.4.5 **Energy Requirement and Cost Models.** The electrical energy requirements of an ESP are modeled separately to allow them to be included in the gross capacity of the "base" power plant. Energy is needed primarily to overcome the pressure drop across the ESP, and to power the ESP corona (including auxiliaries). Thus, the total ESP power is

$$P_{esp} = P_{fan} + P_{corona}. \qquad \text{[Eq 46]}$$

Fan energy is the pressure drop times the gas flow rate divided by the electromechanical efficiency of the fan-motor drive. Published estimates of ESP pressure drops range from 0.5 to 3.0 inches of water. A value of 1.0 inch is assumed here. The product of fan and motor efficiencies is taken as 0.70. Corona energy is represented as the ESP surface area times a design power density, D (watts per square feet), which is assumed to include actual power plus auxiliaries. Based on Reference 22, values of D are taken to be 1.5 for a cold-side ESP and 1.9 for a hot-side ESP. Thus, the total ESP power becomes

$$P_{esp}\,(MW) = [(D)\,(AR)_{esp} + 0.155G] * 10^{-6} \qquad \text{[Eq 47]}$$

where

$P_{esp} =$ total power requirement (MW)

$D =$ corona power density (watts/ft^2) $= \begin{cases} 1.5, \text{ cold ESP} \\ 1.9, \text{ hot ESP} \end{cases}$

$G =$ flue gas flow rate (acfm)

$(AR)_{esp} =$ collector area (ft^2) $= SCA * G$

The cost of electricity to operate an ESP is treated as a variable cost in the AUSM when evaluating control options and cost for a given power plant. The total annual energy requirement is simply the power level in Equation 47 times the annual hours of operation (8760 times capacity factor). The total energy cost then follows from multiplying by a user-specified cost per kilowatt hour.

Thus,

$$energy,\ ESP\,(1981\$/yr) = (P_{esp} * 1000)\,(8760 * CF)\,(UC_{elec}) \qquad \text{[Eq 48]}$$

where

$P_{esp} =$ power from Equation 47 (MW)

$UC_{elec} =$ unit cost of electricity (1981\$/KWh).

It should be re-emphasized that pollution control energy costs are calculated and used only to compare the relative costs of alternative technologies or control options. Once a least-cost device is selected, its reported variable cost in the AUSM excludes the cost of power, since all power production costs are included in the total plant variable cost. The net (dispatchable) capacity of the plant, however, is reduced because of the pollution control device's energy needs. The effect of such deratings is to increase the net plant heat rate and accelerate the additions of new plant capacity in future years.

5.2.5 Economic Performance Models for Fabric Filters

5.2.5.1 Overview. The models of total capital cost and total variables cost for fabric filters also are adopted from Research-Cottrell [5], whose results are in good agreement with other cost estimates [10,24]. The total bag collection area is the flue gas flow rate, G, divided by the air-to-cloth ratio, A/C, an independent parameter of the model. The total variable cost of fabric filtration systems is modeled in terms of the flue gas flow rate and the bag replacement charge. The latter is a function of A/C but also can be specified by the user.

5.2.5.2 Details of the Physical Performance Model. Fabric filter performance can be judged by the dust concentration in the outlet gas. This concentration, called the outlet loading, is most sensitive to air-to-cloth ratio (A/C), the ratio of gas flow rate to fabric area, and largely insensitive to inlet dust concentration.

The use of fabric filters at electric power plants is a very recent development; thus, experience remains quite limited relative to ESPs. Performance data used here are representative of information available in 1980. One recently developed model is moderately successful in predicting outlet dust loading [25]. It is complex and relies on detailed specification of design parameters at a level not appropriate for the AUSM. As an alternative to such a complex mechanistic model for filtration efficiency, an empirical model based on observation of existing units is recommended. Two of the early utility boiler fabric filter installations are at the Pennsylvania Power and Light Company Sunbury Station and the Colorado Ute Electric Association Nucla Station. The capacities of these stations are 170 and 39 megawatts, respectively. The outlet particulate loading for these stations averages about 0.002 grains per cubic foot [12]. A typical design value for maximum outlet loading is 0.005 grains per cubic feet [13]. The suggested model simply applies such a unit emission factor to calculate the particulate emission rate for the actual flue gas production rate:

$$particulate\ emissions\ (grains/min) = outlet\ loading\ (gr/ft^3) * G \qquad [Eq\ 49]$$

where G is gas flow rate (acfm).

The outlet grain loading increases as the air-to-cloth ratio increases. Based on published data [12,26], the outlet loading for A/C in the range 1.8 to 3.0 is approximated by:

$$OL = [10(A/C) - 17.0]\ 10^{-3} \qquad \text{[Eq 50]}$$

where $A/C =$ air-to-cloth ratio in acfm/ft^2

$OL =$ outlet loading in grains per dry standard cubic foot.

In future AUSM development work, refinements to this model will be sought based on additional operating experience as the use of fabric filters increases. In the current model a design outlet loading is specified by the user and used to estimate the air-to-cloth ratio. The fabric filter removal efficiency also can be obtained from the ratio of outlet-to-inlet loading as

$$\eta_{ff} = 1 - \frac{OL}{IL} \qquad \text{[Eq 51]}$$

where $IL =$ calculated inlet loading (flyash concentration, in gr/dscf).

In general, this removal efficiency will be more stringent than emission constraints require. If this is the case, A/C is found from Equation 50 as

$$A/C = 1.7 + 100 * OL. \qquad \text{[Eq 52]}$$

The default value of outlet loading is 0.003 grains/ft^3, giving an air-to-cloth ratio of 2.0. Should the efficiency from Equation 51 be insufficient to meet the imposed emission standard, Equation 51 is used to calculate the compliance value of OL, which is then used to determine A/C. Again, subsequent refinements to this model are planned based on growing experience in the industry.

5.2.5.3 **Capital Cost Model**. Although utility experience with fabric filtration is increasing, reliable cost estimates supported by experience are limited. The Research-Cottrell model [5] has been chosen since it allows easy isolation of direct capital cost and is apparently somewhat conservative:

(1) Basic collector = $1.20\ (AREA)^{1.07}$

(2) Bag and hardware = (bag cost -0.50)($AREA$)

(3) Mechanical components = 0.20 * (Basic Collector)

(4) Electrical components = 0.20 * (Basic Collector)

(5) Insulation = 0.45 * (Basic Collector)

(6) Structural support $= 0.12 * (\text{Basic Collector})$

(7) Erection and installation $= 285\,(AREA)^{0.72}$

Thus,

$$\begin{aligned} TDC,\ \mathit{fabric\ filter}\ (1977\$) &= 2.364(AREA)^{1.07} \\ &\quad + 285(AREA)^{0.72} \\ &\quad + (\mathit{bag\ cost} - 0.50)(AREA) \end{aligned} \qquad \text{[Eq 53]}$$

where bag cost is in 1977 dollars per square foot, and *AREA* is the fabric filter area in square feet, equal to the air-to-cloth ratio (A/C) times the gas flow rate (G).

Combining the first two terms, as was done for the ESP models, and escalating to 1981 dollars using the Chemical Engineering plant index:

$$TDC(1981\$) = 39.86(AREA)^{0.94} + (\mathit{bag\ cost} - 0.73)(AREA). \qquad \text{[Eq 54]}$$

The last term is used to accommodate bag costs that differ from the value of 50 cents/ft^2 (1977 basis) assumed in the Research-Cottrell model. Accepting Research-Cottrell's bag cost and adding the ash handling cost (Equation 40), we obtain the equation utilized in the AUSM for fabric filter direct capital costs:

$$TDC(1981\$) = 39.86(AREA)^{0.94} + 6424 * MW. \qquad \text{[Eq 55]}$$

The nominal indirect cost factor used for fabric filters utilized with wet FGD is 0.50, or 0.36 excluding AFUDC. This is the same as for ESPs, reflecting recent utility experience with this technology [13]. When a fabric filter is combined with the new SO_2 control technologies of dry lime FGD and LIMB, an indirect cost factor of 0.55, or 0.41 excluding AFUDC, is utilized. This increase is due to an increased contingency allowance that is associated with limited operating experience.

5.2.5.4 **Variable Cost Model, Excluding Utilities.** The variable cost component of total revenue requirement includes materials and labor for operating and maintenance, power, and bag replacement. The materials and labor costs are slight—about 0.03 mills per kilowatt hour, in 1981 dollars [10,27].

Bag replacement cost is calculated by

$$BRC = AREA(ft^2) * bag\ cost\ (\$/ft^2)/bag\ life\ (years) \qquad [Eq\ 56]$$

The total variable cost, excluding power, is then

$$\begin{aligned} TVC &= 0.03\ MW * CF * 8760 + BRC \\ &= 262 * MW * CF + BRC \qquad [Eq\ 57] \end{aligned}$$

where $MW =$ gross power plant capacity (MW)

$CF =$ annual average capacity factor (fraction)

$TVC =$ total variable cost, excluding utilities (1981\$).

In the absence of other information, bag life is assumed to be two years when A/C is 2.0 feet per minute and one year when A/C is 3.0 feet per minute. That is,

$$bag\ life = 4.0 - A/C \qquad [Eq\ 58]$$

where $1.8 \leq A/C \leq 3.0$.

This is consistent with the Research-Cottrell assumptions. Additional discussions of comparisons between these cost models, alternative models, and representative data are included in Reference 28.

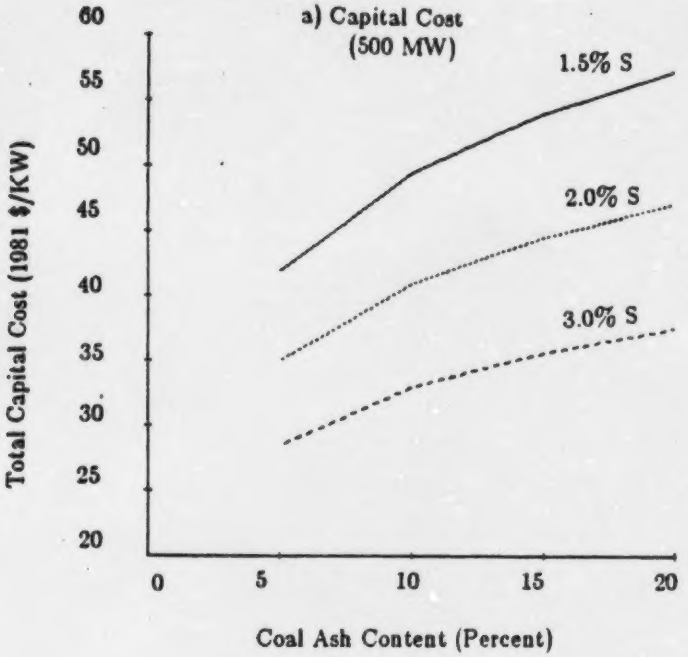
5.2.5.5 **Energy Requirement and Cost Models.** The electric energy penalty for a fabric filter is simply the fan energy needed to overcome the pressure drop across the device. Based on average estimates, this is taken to be six inches of water with an air-to-cloth ratio of 2.0. For other values of A/C, pressure drop is assumed to be proportional to the 2.5 power of (A/C). The electromechanical efficiency of the fan-motor system is taken to be 70 percent. The power consumption is then

$$P_{ff}\,(MW) = 9.28 * 10^{-7}\ G * \left(\frac{2.0}{A/C}\right)^{2.5} \qquad [Eq\ 59]$$

where P_{ff} is the power requirement in megawatts and G is the flue gas flow rate (acfm). Energy costs are then computed as in Equation 48.

Figure 5-3 shows ESP capital and variable costs as a function of coal sulfur and ash content for a 500 MW power plant operating at the current NSPS of 0.03 pounds TSP emissions/10^6 Btu fuel input. Both show significant increases as sulfur and ash contents increase. Capital and operating costs from the fabric filter model for the same conditions are shown in Figure 5-4. The capital cost is unaffected by coal

Figure 5-3
ILLUSTRATIVE RESULTS USING AUSM ESP COST MODEL



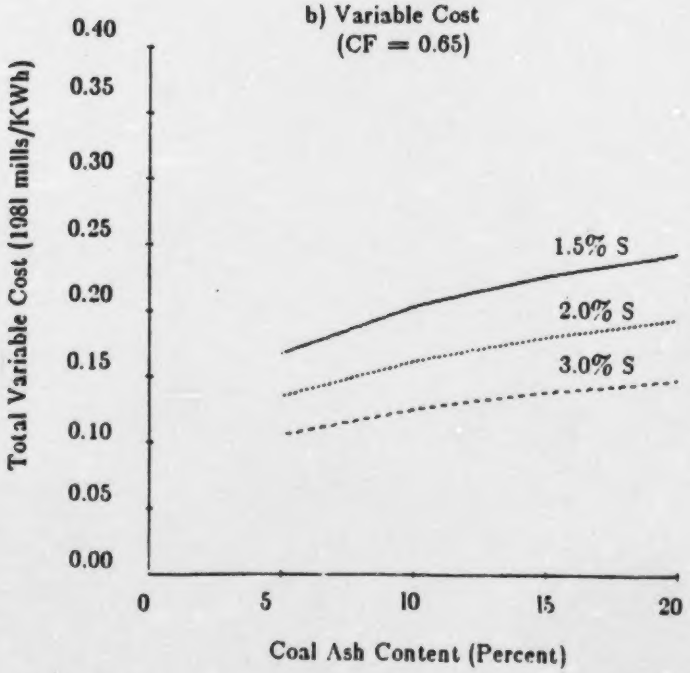
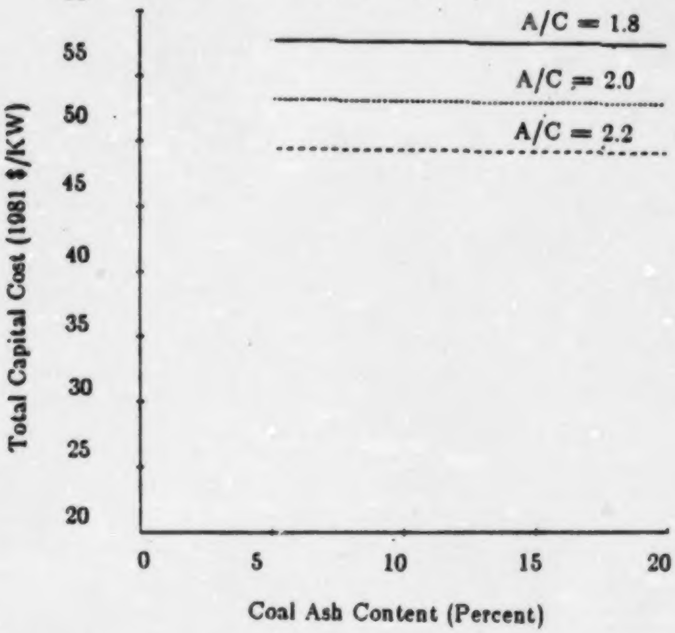


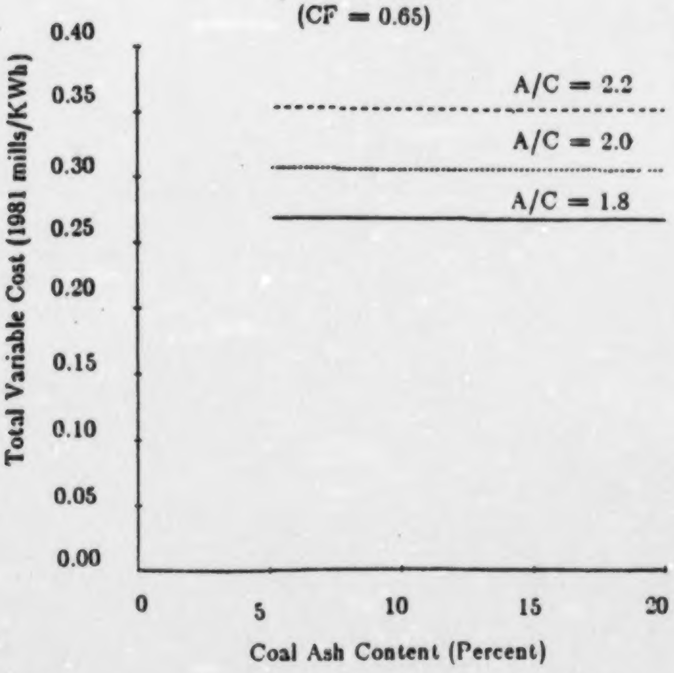
Figure 5-4

ILLUSTRATIVE RESULTS USING AUSM FABRIC FILTER COST MODEL

a) Capital Cost
(500 MW)



b) Variable Cost
(CF = 0.65)



ash content but increases as the air-to-cloth ratio decreases. This is contrasted to the variable cost which increases as the air-to-cloth ratio increases. The increase in variable cost is due to increased fan electricity consumption needed to overcome the increased pressure drop that is associated with a higher air-to-cloth ratio. Both Figure 5-2 and Figure 5-3 are based on the same plant and economic assumptions.

5.2.6 Economic and Performance Models for a Wet Limestone FGD System

5.2.6.1 **Overview**. The most common flue gas desulfurization system in the United States is a wet-scrubbing system employing limestone as the reagent. In developing the economic models reported here, extensive use has been made of the Tennessee Valley Authority (TVA) computer models for detailed cost estimation of lime/limestone systems [29,30,31], which have been compared with other models for estimating FGD system costs [32,33]. All results suggest that the direct capital cost of limestone systems can be reliably estimated in terms of the maximum expected values of the flue-gas volumetric flow rate, and the mass rate of sulfur dioxide removal. As indicated earlier, the gas flow rate depends principally on the gross power plant size and heat rate. If only partial scrubbing is employed, the gas flow rate through the scrubber also depends on the fraction of total gas bypassed. The design mass removal rate of SO_2 depends principally on power plant size, coal sulfur content, plant heat rate, and air pollution emission constraints.

FGD system capital costs were determined for two subsystems: reagent handling and individual scrubber trains. These were determined from a multiple regression analysis of costs predicted by the TVA model [31] over a wide range of power plant sizes, heat rates, and coal characteristics. Scrubber configurations with and without forced oxidation were considered, as were different design values of limestone stoichiometry, scrubber liquid-to-gas ratio, and number of spare trains to enhance FGD system reliability.

Simplified models of total variable cost also were developed using least squares multiple regression analysis of results from the TVA program. Here, too, the flow rate of flue gas and the mass removal rate of SO_2 (based on the annual average capacity factor rather than on maximum or design capacity) were the key determinants of variable cost, in addition to the reagent cost, which is directly proportional to the mass of SO_2 removed.

5.2.6.2 Capital Cost Model

The FGD cost algorithms have been developed using linear regression analysis of data from 150 executions of the TVA program [31]. Revisions to this program are routinely acquired and implemented at Carnegie-Mellon University. The analyses presented here utilized the 1982 version of the model. Values of significant input variables for these runs are summarized in Table

Table 5-6

INPUT VARIABLES FOR TVA MODEL

Plant Capacity (MW)	Percent Sulfur in Feed Coal[a]	Number of Operating Trains[b]
125		1
250	0.5 to 7.5%,	2
375	increasing	2 or 3
500	by 0.5%	3,4, or 5
625	increments	4,5, or 6
750	for each	4,5,6, or 7
875	power plant	5,6,7, or 8
1000	capacity	6,7,8,9,10, or 11
1125		6,7,8,9,10, or 11
1250		7,8,9,10,11, or 12

[a] *This gives 15 runs for each plant size. Carbon content was reduced as sulfur content increased.*

[b] *The numbers indicated were used in continuous serial rotation for the set of 15 runs at the indicated plant size. For example, the 500 MW plant was assumed to have three operating trains with 0.5%S, four with 1.0%S, five with 1.5%S, then three with 2.0%S, four with 2.5%S, ..., etc.*

5-6. Values for other variables were held constant and can be obtained from the sample input of Table 5-7.

The TVA program itemizes direct capital costs for the scrubbing unit separately from those for materials handling and preparation facilities. These two components are modeled separately, as described below.

5.2.6.2.1 **Materials Handling and Preparation.** Figure 5-5 is a plot of direct capital cost versus annual limestone utilization for materials handling and preparation systems for our 150 cases. These data may be approximately represented by a piecewise linear curve with a step change at 99 K-tons/year. Linear regression for the data above and below this value yields:

$$DCC,\ materials\ handling\ (10^3\ 1981\$) = 2859 + 24.06 * L(L < 99) \qquad \text{[Eq 60]}$$

$$DCC,\ materials\ handling\ (10^3\ 1981\$ = 5393 + 13.25 * L(L \geq 99) \qquad \text{[Eq 61]}$$

where L = annual limestone utilization in 10^3 tons @ 5500 hrs/year.

Assuming that the materials handling and preparation capacity must match the scrubber capacity, the costs can be expressed as a function of the reagent handling system capacity:

$$L = CAP * 5500/10^3 \qquad \text{[Eq 62]}$$

where, by definition, CAP = WSR * S

CAP = reagent handling system capacity (tons/hr)

S = SO_2 removal rate capacity (tons/hr)

WSR = weight stoichiometric ratio (lb reagent required/lb SO_2 removed).

Substituting Equation 62 into Equations 60 and 61 gives:

$$DCC,\ materials\ handling\ (10^3\ 1981\$) = 2859 + 132.3 * CAP(CAP < 18) \qquad \text{[Eq 63]}$$

$$DCC,\ materials\ handling\ (10^3\ 1981\$) = 5393 + 72.88 * CAP\ (CAP \geq 18) \qquad \text{[Eq 64]}$$

The R^2 values are 84.6 percent and 99.1 percent for Equations 60 and 61, respectively, with 50 and 96 degrees of freedom (d.f.). In both cases, the residuals are normally distributed without evident systematic bias; the largest residuals are about 3 percent of the observed values.

Table 5-7
SAMPLE INPUT TO TVA PROGRAM FOR CALIBRATION OF FGD MODEL

```
1 1 1 1 1
1 1 1 1 1 1 1 1 1 1 1 1
1 1 1
RUN # 1.1 125MW, 0.57%S, 1 OPTR, O RDTR, 69.%C
2 125 9700 11700 39 300 2 0 0 90 0 0 0 0 175 3 470 751
1 69.2 3.7 6.0 1.4 0.57 .1 15.1 4.0 92 80 2 .03 0.03
90 0 0 10 25 4 0.0 10 1 0.0 1 0.0 1 0 0.15 0 0 0 4.85 5 0 0
15 40 0.2 40 0 35 2.5 80 1.2 0 0 9 0 14.7 1
1 0 0.2 0 35 .0000005 32 10 5.70 1 0 0 .1
1 0 9999 5000 0 25 5280 3 0 0
7 2 16 5 10 8 15.6 10 8 3 6 1 60 1.886 14.7 7 0.0
1 4 3.5 6 0 1 1.5 1 2 1 8 5 10 0
8.50 75.00 460 1200 15 2.5 0.14 0.037 21.00 325.0 239.0 1981 1983
4 1 5 .8 1.0 3 .65 1 1 1.1 1981 292.0
NEXT
```

LINE 1,2,3: printer control variables (all "1")

LINE 4: TITLE: identifies the current value of each parameter varied in this set of runs.

Run #1.1 125 MW, 0.57.%S, 1 OPTR, O RDTR, 69% C

LINE 5: Particulate collection device option

1. *ESP = 2 separate particulate collection
2. *MW = 125 to 1250 (gross capacity in MW)
3. BHR = 9000 Btu/KWh boiler heat rate
4. HVC = 11700 Btu/lb (moist basis)
5. EXSAIR = 39% excess air
6. THG = 300°F, temperature of hot gas to scrubber
7. XRH = 2 (steam reheat)
8. KEPASS = 0, no emergency bypass provided
9. KPASO2 = 0, no partial scrubbing bypass
10. PSSO2X = 90 (% removal in scrubber when the bypass option is selected (KPASO2 = 1)). For these cases it has no effect.
11. KCLEAN = 0, no coal cleaning
12. WPRCVR = 0, yield of cleaning plant

Table 5-7 (contd.)

---

13. WPPSAC = 0, % pyritic sulfur plus ash in cleaned coal
14. WPPSRC = 0, % pyritic sulfur plus ash in raw coal
15. TSK = 175°F, stack gas temperature
16. TSTEAM = 470°F, reheat steam temperature
17. HVS = heat of vaporization of reheat steam = 751 (Btu/lb)

LINE 6:

1. INOPT = 1, coal composition given as weight percent
2. *WPC = WT.% carbon = 69.7-WPSUL
3. WPH = 3.7% hydrogen
4. SPO = 6.0% oxygen
5. WPN = 1.4% nitrogen
6. *WPSUL = 0.5 to 7.0% sulfur by 0.5% increments
7. WPCL = 0.2% chlorine
8. WPASH = 15.1% ash
9. WPH20 = 4.0% H_20
10. SULO = 92%, fraction sulfur to flue gas
11. ASHO = 80%, fraction ash to flue gas
12. IASH = 2, particulate emission limit to be specified in $\#/10^6$ Btu
13. ASHUPS = 0.03, particulate emission from dry collector
14. ASHSCR = 0.03, particulate emissions from scrubber

LINE 7: SO_2 removal options

1. XLG = 90 gal/kft^3 liquid-to-gas ratio in scrubber
2. VLG = 0, venturi L/G (not used)

Table 5-7 (contd.)

3. VTR = 0, extra hold tank residence time (not used with spray tons)
4. V = 10 ft/sec, scrubber gas velocity
5. VRH = 25 ft/sec, reheater gas velocity
6. ISO2 = 4 (revised NSPS assumed for SO_2)
7. XSO_2 = 0.0, value for SO_2 removal; ignored for ISO_2 = 4 and calculated by the program
8. TR = 10 minutes, hold tank residence time
9. XSR = 1, stoichiometric reagent requirement to be calculated based on L/G and SO_2 removal requirement
10. SRIN = 0.0, stoichiometric ratio (calculated by program)
11. XIALK = 1, limestone reagent
12. IADD = 0, no M_gO or adipic acid added
13. WPMGO = 0.15
14. XMGOAD = 0
15. AD = 0
16. ADDC = 0
17. WPJ = 4.85
18. WPM = 5
19. ASHCAO = 0
20. ASHMGO = 0

LINE 8:

1. WPS = 15% solids in recycle to slurry
2. PSD = 40% solids in sludge discharge
3. RS = 0.2 ft/hr clarifier settling rate
4. PSC = 40% solids in clarifier underflow
5. IFOX = 0, no forced oxidation

Table 5-7 (contd.)

---

6. OX = 35% oxidation of sulfite to sulfate
7. SRAIR = 2.5 g-atoms0/g-mol SO_2, air stoichiometry (this is a conservative value used by TVA)
8. PSF = 80% solids in filter cake
9. FILRAT = 1.2 filtration rate
10. PHLIME = 0.0 (not applicable)
11. IVPD = 0
12. VPD = 9
13. PELTAP = 0
14. PRCS = 14.7
15. IFAN = 1 (induced draft)

LINE 9:

1. ISCRUB = 1
2. XNS = 0 (not applicable)
3. XNG = 0 (not applicable)
4. HS = 0 (not applicable)
5. RAIN = 35 inches/year
6. SEEPRT = 0.0000005
7. EVAPRT = 32 inches/year
8. WINDEX = 10 limestone hardness factor (wi)
9. HPTONW = 5.70 hp/(ton) (wi) grinding factor
10. NSPREP = 1 redundant prep unit

Table 5-7 (contd.)

---

11. NO TRAN = number of operating scrubbing trains (varied)

12. NO REDN = number of redundant scrubbing trains (varied)

13. PCNTRN = 0.1% entrainment
LINE 10: waste disposal options

1. I SLUDG = 1, onsite ponding

2. SDFEE = 0.0; sludge treatment fee

3. PSAMAX = 9999; maximum disposal area in acres

5. ACRES = $5000/acre; disposal land cost

5. PDEPTH = 0

6. PMXEXC = 25; maximum excavation depth in feet

7. DISTPD = 5280; distance to pond in feet

8. ILINER = 3; pond liner option

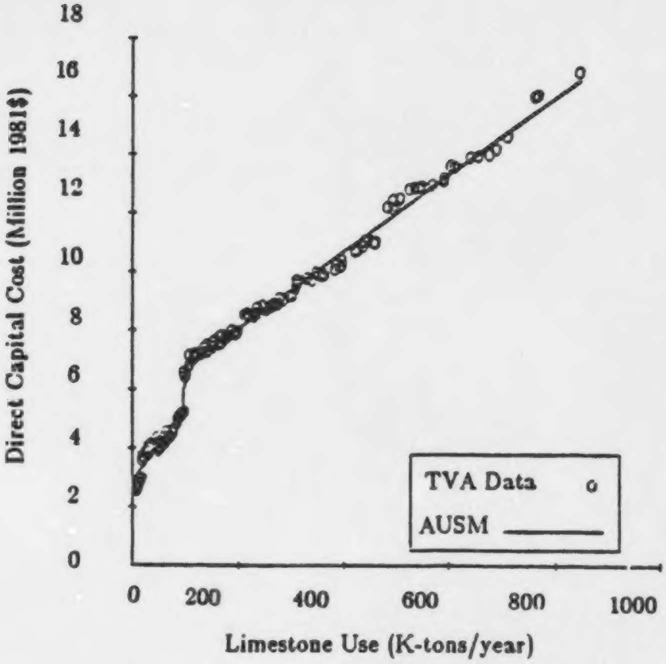
9. XLINA = 0

10. XLIWB = 0

5 - 10 pertain only to ponding

LINES 11, 12, 13: These lines include economic assumptions for indirect costs, material cost fixed charges, and labor rates. Current TVA base case assumptions are accepted.

Figure 5-5
AUSM PREDICTED LIMESTONE HANDLING AND PREPARATION COST VERSUS TVA MODEL



Other regression analyses also were performed to fit the TVA data in more detail, since results of the 150 case studies showed several step changes at various limestone capacities due to assumptions regarding equipment selection and redundancy (e.g., handling equipment for reagent shipment by rail versus truck). By defining seven piecewise linear intervals (as opposed to two), slightly different costs were predicted for high limestone use, with R^2 values no less than 84.4 percent across the entire range. This also was done for cases in which various values of reagent stoichiometry (rather than liquid-to-gas ratio) were specified as model inputs (in all, some 600 runs of the TVA model). However, predicted cost differences between the 7-segment and 2-segment formulations were judged to be too small to warrant the added computational complexity in the context of the AUSM.

5.2.6.2.2 **Scrubber Modules and Trains.** The scrubber is of modular construction. Individual modules or scrubbing trains have a capacity between 100 and 200 megawatts. Larger plant capacities are accommodated by using additional operating trains. These are distinguished from redundant trains that are not required to handle plant capacity but act as spares. The total direct cost of the scrubbing unit is:

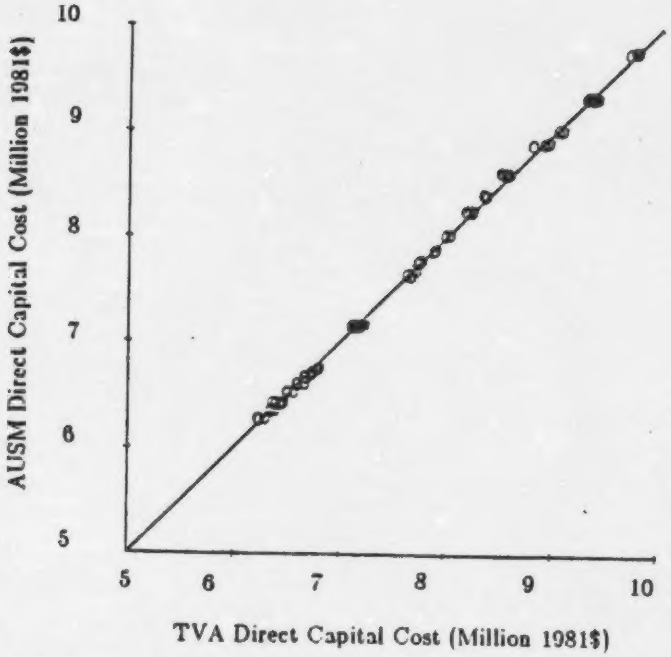
$$DCC_{scrubber} = (NOP + NRD) * (module\ cost) \qquad [Eq\ 65]$$

where NOP = number of operating trains

NRD = number of redundant trains

The per module direct capital cost was obtained from the results of the 150 executions by dividing the output variable "total direct process investment" for scrubbing by the number of operating modules. The sulfur dioxide removal rate, S, and gas flow rate, G, per module were selected as independent variables and were found to account for virtually all variation in the direct cost. No significant economy of scale was suggested since a linear relationship of costs to these variables correlates well with the TVA results, as illustrated in Figure 5-6. This is not surprising because the range of sizes possible for single modules is small (100 to 200 megawatts). Regression of the per module direct capital cost on per module

Figure 5-6
AUSM PREDICTED SCRUBBER MODULE COST VERSUS TVA MODEL



S and G yields:

$$module\ DCC\ (10^3\ 1981\$) = 2781 + (40.6S + 0.0108\ G)/NOP \qquad [Eq\ 66]$$

where $S =$ total scrubber SO_2 removal rate capacity (tons/hr)

$G =$ total scrubber gas flow rate capacity (acfm @ 300°F)[6]

$NOP =$ number of operating modules (integer).

The value of R^2 for Equation 66 is 99.9 percent with 147 degrees of freedom.

The module DCC is used in Equation 65 to calculate the total scrubbing cost. The number of operating trains (NOP) and redundant trains (NRD) is estimated as:[7]

$$NOP = MW(1 - f_{byp})/125\ (nearest\ integer) \qquad [Eq\ 67]$$

$$NRD = NOP/4\ (truncated\ integer;\ min. = 1) \qquad [Eq\ 68]$$

The cases above are for scrubbers without forced oxidation, which has been the prevalent design until recently. Now, however, plants increasingly are turning toward forced oxidation of sludge to facilitate solid waste handling and disposal. The additional scrubber module components needed for forced oxidation are a sparger ring, oxidation bleed pumps, and air compressors. The effects of these additions are shown in Table 5-8. Across a range of coal types and power plant sizes the average cost increase for forced oxidation is 4.0% ± 0.3%. In light of the small variation, a constant multiplier of 1.04 is therefore applied to Equation 66 for forced oxidation systems. This is the AUSM default option.

In defining the material handling, preparation and scrubber design characteristics, it is often desirable to account for the variation in coal sulfur content. This is accomplished in the AUSM by adjusting the annual average coal sulfur content with a multiplier that reflects its short-term variation. The multiplier utilized in the AUSM is based on coal type, emission averaging time, and emission exemption status as shown below [15,34]:

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[6] If only partial scrubbing is employed, the gas flow rate through the scrubber is the total flue gas rate time $(1 - f_{byp})$, where f_{byp} is the gas bypass fraction not scrubbed (see Equation 26).

[7] See footnote 6.

Table 5-8
EFFECTS OF FORCED OXIDATION ON SCRUBBER DIRECT CAPITAL COST[a]

Case Number	Coal (%S)	Size (MW_g)	SO_2 Removal (TPH)	With Oxidation ($/KW)	Without Oxidation ($/KW)	Difference ($/kW)	Percent Difference
1	2.0	250	3.36	52.40	50.56	1.84	3.64
2	5.0	250	8.40	53.44	51.32	2.12	4.13
3	2.0	500	6.72	51.46	49.56	1.90	3.83
4	5.0	500	16.79	52.42	50.26	2.16	4.30
5	2.0	1000	13.43	51.13	49.25	1.88	3.82
6	5.0	1000	33.58	52.13	49.91	2.22	4.45
Average				52.18±0.82	50.14±0.74	2.02±0.16	4.03±0.31

[a] *For all cases, HR = 9500 Btu/KWh; SO2 removal = 90%; HHV - 11,700 Btu/lb; excess air = 39%; no ash removal in scrubber; 1980 dollars; T = 300F.*

$$S_{rsd} = S_{avg} * (1 + n * RSD) \qquad \text{[Eq 69]}$$

where S_{rsd} = adjusted coal sulfur content

S_{avg} = annual average coal sulfur content

n = coal sulfur relative standard deviation multiplier (equal to 3 for the cases of 30-day averaging time or no exemptions)

RSD = coal sulfur relative standard deviation defined by Table 5-9 (default = 0.0).

5.2.6.2.3 **Indirect Cost Factors.** The indirect costs of FGD systems currently are modeled as a single user-specified parameter, with a default value of 0.80, based on typical results of the TVA model [31]. Interest during construction typically accounts for 23 percent of this. Thus, the AUSM default value is

Table 5-9

RSD DEFAULT PARAMETERS [15]

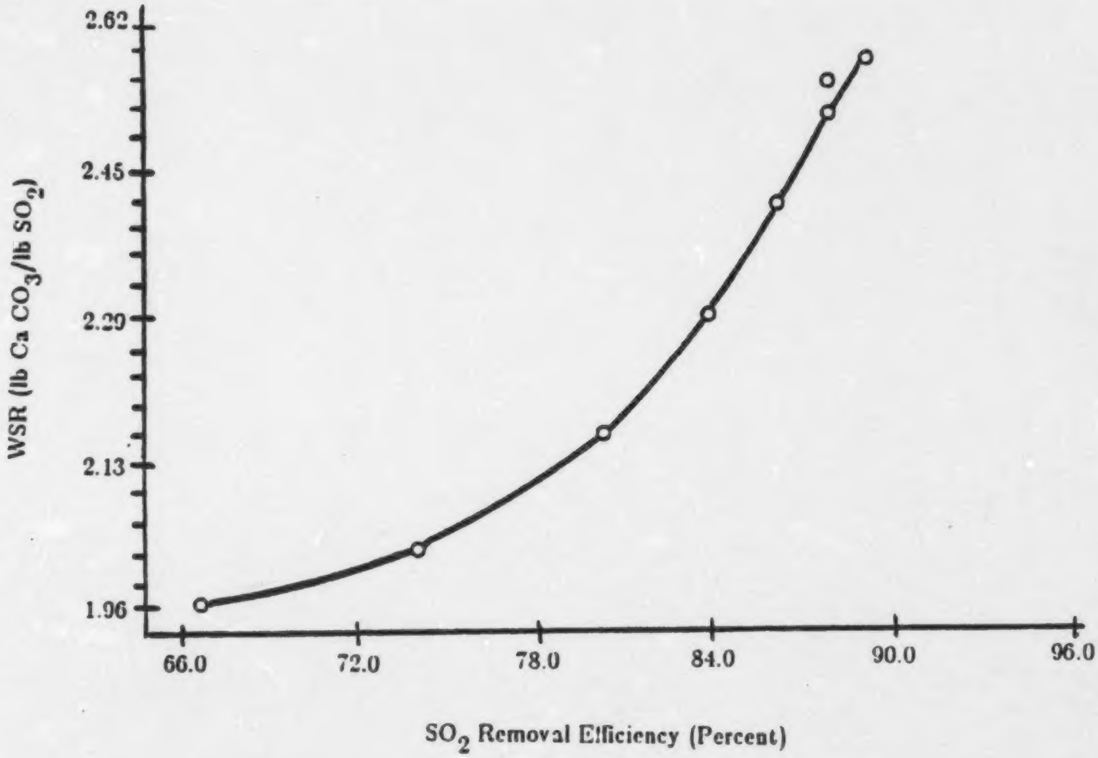
Coal Type	*Averaging Time* 1-day	30-day	1-year
Uncleaned bituminous coal	0.15	0.069	0.0
Lignite, sub-bituminous, and cleaned bituminous coal	0.075	0.073	0.0

reduced to 0.57, and AFUDC is then added explicitly, as discussed earlier.

5.2.6.2.4 **Effects of Reagent Stoichiometry**. The 150 cases summarized in Tables 5-6 and 5-7 assume that plants meet the current NSPS for SO_2, which specifies a percentage reduction requirement of from 70 to 90 percent of potential emissions, and a ceiling of 1.2 pounds SO_2/MBtu. The TVA program translates this requirement into a necessary scrubber efficiency based on the coal sulfur content, heating value, and the fraction of sulfur that enters the flue gas. The necessary limestone requirement (stoichiometry) is then calculated based on the semi-empirical algorithms in the TVA model, together with the nominal scrubber design parameters (Table 5-7). Alternatively, the stoichiometry can be specified, and the scrubber liquid-to-gas ratio (L/G) calculated.

Figure 5-7 is a plot of stoichiometric ratio versus SO_2 removal efficiency for the 150 cases described earlier. Here, the liquid-to-gas ratio (L/G) was assumed to be constant at 90 gallons per thousand cubic feet, as typically assumed by TVA. In the AUSM, the stoichiometric ratio thus has been treated as a function of SO_2 removal efficiency only. The curve of Figure 5-7 appears parabolic. Translation to the origin and transformation of the efficiency axis by a power of 2.5 results in a satisfactory fit, with R^2

Figure 5-7
STOICHIOMETRIC RATIO VERSUS EFFICIENCY
(L/G = 90)



equal to 99.9 percent (148 degrees of freedom) and no evident systematic error. The relationship is:

$$WSR = 1.98 + 25.5\,(\eta_{SO_2} - 0.67)^{2.5}. \qquad \text{[Eq 70]}$$

For limestone ($CaCO_3$), molar stoichiometry (MSR) is 0.65 times weight stoichiometry. Thus, Figure 5-7 shows that for an L/G of 90, the molar stoichiometric ratio increases from about 1.2 to 1.7 as the SO_2 removal efficiency increases from approximately 70 to 90 percent.

To minimize scaling and other potential problems the practical limitation on stoichiometry is about 1.4. This requires a higher L/G to obtain high removal efficiencies. Figures 5-8, 5-9, and 5-10 show partial results of sensitivity analyses conducted with the TVA model to display the effects of different combinations of L/G and stoichiometry. In these runs, a system with forced oxidation was assumed. In Figure 5-8, the values of L/G and molar stoichiometry needed to achieve a given SO_2 removal efficiency are seen. (This is independent of the coal sulfur content for the cases considered.) Figures 5-9 and 5-10 show the total direct capital cost and the total first-year revenue requirement, respectively, for two cases: (1) L/G constant at 90 gallons per thousand cubic feet, and (2) MSR constant at 1.4. Studies also were performed for a constant stoichiometry of 1.1 and for a linear increase in stoichiometry with removal efficiency. Separate regression equations for scrubber capital and operating costs were developed for each case. Figure 5-9 shows that the lowest annual costs are obtained by optimizing the scrubber design for specific plant parameters (which would not be feasible in the AUSM). However, capital and annual costs for various combinations of L/G and stoichiometry are seen to be within less than 5 percent of each other for L/G between approximately 80 and 120 gallons per thousand cubic feet. Based on these results, the materials handling and scrubber cost equations are retained, and the stoichiometric ratio given by Equation 70 is slightly reduced to give better agreement across a variety of detailed system designs involving tradeoffs between L/G and stoichiometry within the limits noted above. Thus, the relationship used in

Figure 5-8

LIQUID-TO-GAS RATIO VERSUS STOICHIOMETRY TRADEOFF

(500 MW Power Plant, TVA Assumptions)

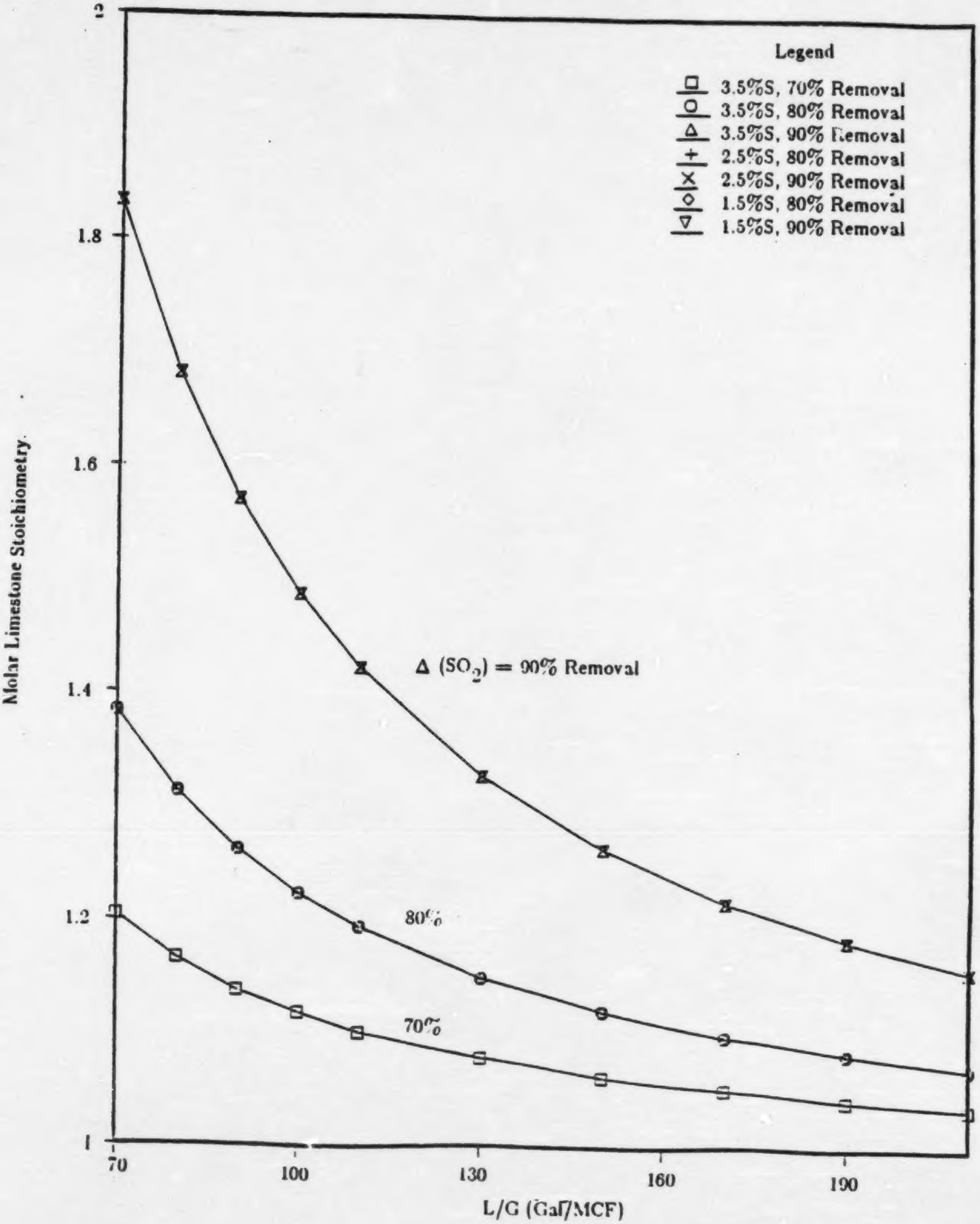


Figure 5-9
CAPITAL INVESTMENT FOR STOICHIOMETRY 1.4
VERSUS LIQUID-TO-GAS RATIO OF 90
(500 MW Power Plant, TVA Assumptions)

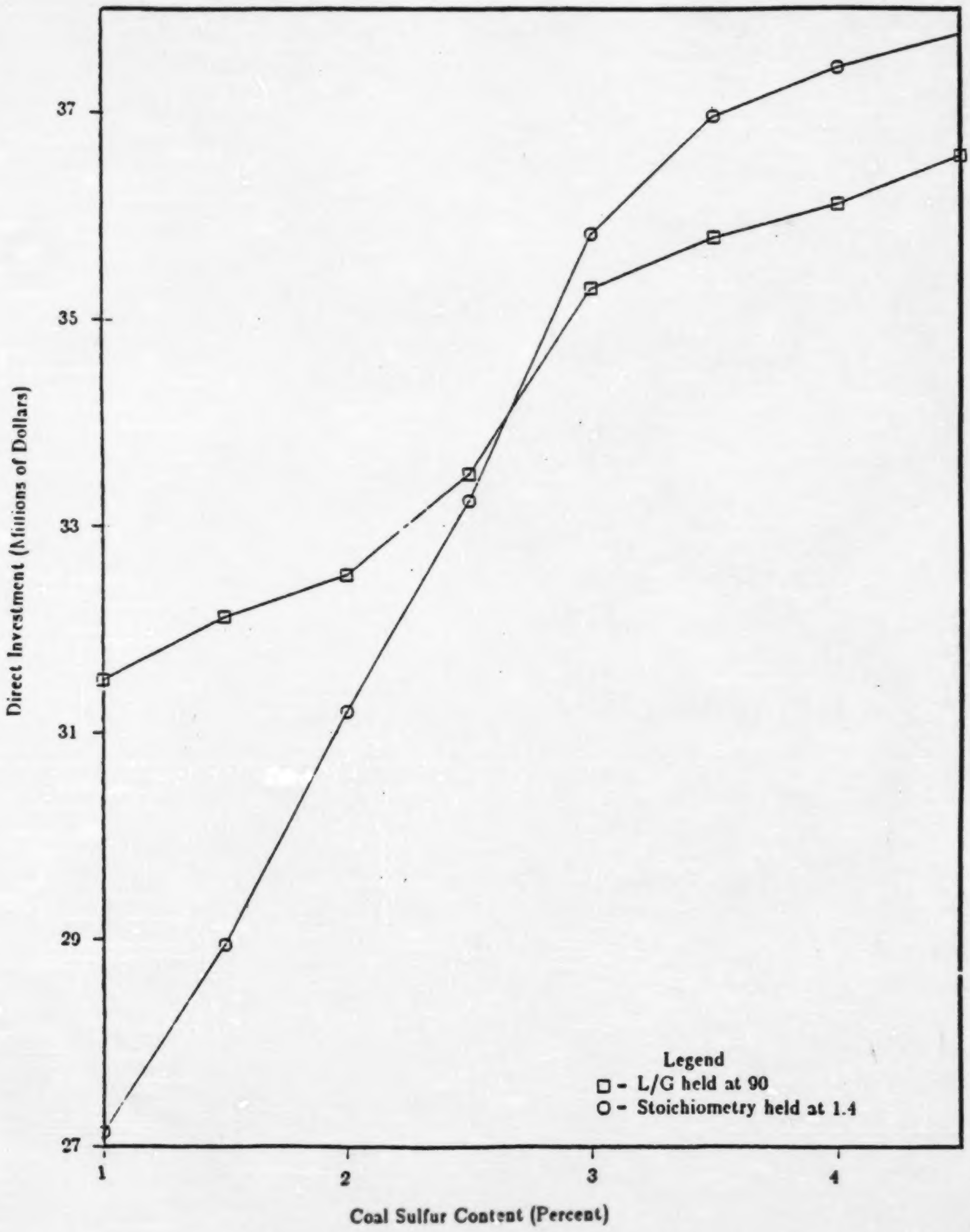
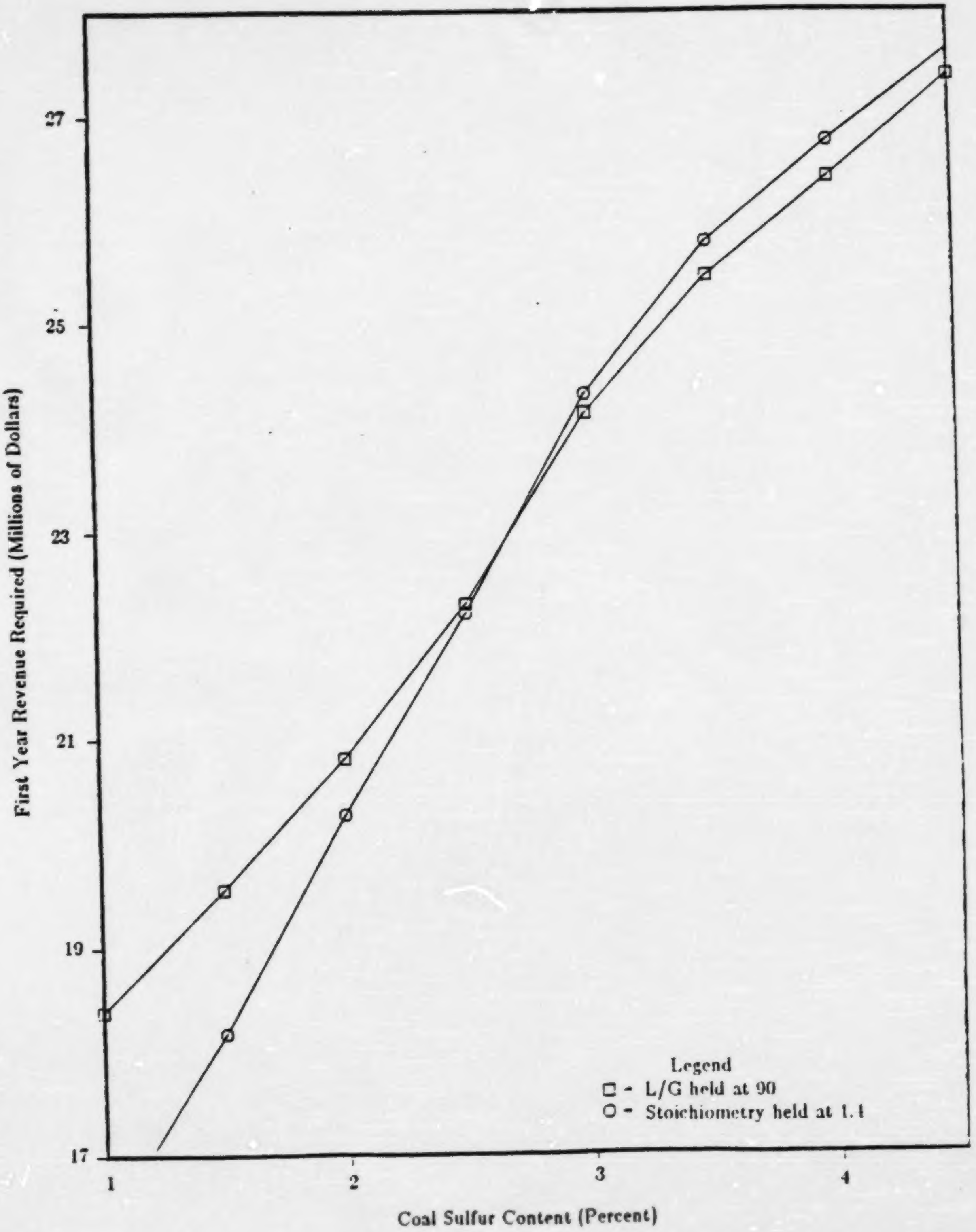


Figure 5-10

FIRST-YEAR COST FOR STOICHIOMETRY 1.4 VERSUS LIQUID-TO-GAS RATIO OF 90

(500 MW Power Plant, TVA Assumptions)



the AUSM is:

$$WSR = \begin{cases} 1.72 + 25.5\,(\eta_{SO_2} \quad 0.67)^{2.5}\,(0.7 < \eta < 0.95) \\ \\ 1.72\,(\eta \leq 0.70). \end{cases} \qquad [\text{Eq } 71]$$

5.2.6.3 **Variable Cost Model, Excluding Utilities.** The variable revenue requirement, excluding utilities, includes raw material costs, labor, and supervision (as before, utility costs are treated separately). As described in the materials handling and preparation discussion, reagent usage can be estimated as a function of SO_2 removal rate capacity.

$$\textit{annual reagent consumption } (tons/yr) = CAP * \textit{annual hours of operation} \qquad [\text{Eq } 72]$$

where *CAP* is the system capacity for materials handling and preparation in tons per hour. Of those items listed as conversion costs, only the nonutility items are included in this variable cost model. Steam and electricity generated from within the power supply system boundaries are charged separately (see Section 5.2.6.4). Water costs are negligible. Overhead is 60 percent of these nonutility conversion costs.

The sum of chargeable conversion costs and overhead for the 150 cases has been correlated with the SO_2 removal rate, S, and the gas flow rate, G, using multiple regression. The result is the following equation (R^2 equals 98.7 percent with 147 degrees of freedom):

$$VRR,\,(1981\$) = (1.82 + 0.130 * S + 3.32 * 10^{-6} * G) * CF * 10^{6} \qquad [\text{Eq } 73]$$

where $S =$ SO_2 removal rate capacity (ton/yr)

$G =$ gas flow rate capacity (acfm)

$CF =$ annual average capacity factor (fraction)

$VRR, =$ variable revenue required for operation (1981\$).

The additional variable revenue requirement for reagent is

$$VRR, = ARC * RC \qquad [\text{Eq } 74]$$

where $ARC =$ annual reagent consumption (ton/yr)

$RC =$ reagent cost (\$/ton)

The annual reagent consumption is

$$ARC = CAP * CF * 8760 \qquad \text{[Eq 75]}$$

where $CAP = WSR * S$ and WSR is the weight stoichiometric ratio as described previously. Reagent cost for limestone is about $8.50 per ton. The total variable revenue requirement is

$$VRR = VRR_s + VRR_r \qquad \text{[Eq 76]}$$

Note that TVA variable costs apply to a different base year than do capital costs. Here, reported 1983 variable costs have been deflated and expressed in 1981 dollars.

Variable costs also were compared for systems with and without forced oxidation. Recall that the TVA model breaks the operating costs into six categories: (1) limestone, (2) operating labor and supervision, (3) utilities, (4) maintenance labor and material, (5) chemical analysis, and (6) plant and administrative overhead. Of these, items 3, 4, and 6 increase with forced oxidation. Utility (electricity and steam) use is explicitly considered later. Plant and administrative overhead increases, since it is calculated as 60 percent of the sum of items 2 through 5. An analysis was conducted with the 12 case studies shown in Table 5-8, comparing costs with and without forced oxidation. The average cost increase was 4.3 percent. As with the direct capital cost, there was about a 1 percent effect seen as the coal sulfur varied from 2 to 5 percent. The effect of forced oxidation varied from 3.4 percent (case 1) to 5.2 percent (case 6). Since this was larger than with direct capital cost, both a linear regression and a fixed fraction prediction were examined. The error in the regression ranged from 0.8 percent to 6 percent. The results of increasing the variable costs by a constant 4 percent gave errors ranging from 0.05 percent to 1 percent, clearly better than the regression. Using exponential scaling might improve the regression, but was not believed warranted. Thus, the recommended model for forced oxidation is a constant multiplier of 1.04 applied to Equation 73. This is the AUSM default.

5.2.6.4 **Energy Requirement and Cost Model.** FGD energy consumption is expressed as a fraction of gross power plant capacity. It has two principal components: (1) electricity utilized for pumps and fans and (2) steam for stack gas reheat.

The annual electricity consumption correlates well with the SO_2 removal and gas flow rates. The former is related to slurry pumping energy, and the latter, to fan energy. The following relationship is based on linear regression analysis for the set of 150 cases (R^2 equals 99.9 percent with 147 degrees of freedom). It can be used to estimate the energy penalty associated with flue gas desulfurization without forced oxidation.

$$AEC = (1.77 * 10^6 + 1.2 * 10^6 S + 23.1 * G) * \frac{8760}{5500} * CF$$

$$= (2.82 * 10^6 + 1.9 * 10^6 S + 36.8 * G) * CF \qquad \text{[Eq 77]}$$

where $AEC =$ annual electricity consumption (KWh)

$S =$ SO_2 removal rate capacity (ton/hr)

$G =$ gas flow rate capacity through scrubber (acfm)

$CF =$ capacity factor (fraction).

For systems with forced oxidation, electricity costs are higher because of additional power needed for the oxidation bleed pumps and air blowers. A separate analysis suggests a correlation dependent on coal sulfur content:

$$(AEC)_{forced\ ox} = (1 + 0.035 \% S) * (AEC)_{without\ forced\ ox} . \qquad \text{[Eq 78]}$$

FGD electricity use as a fraction of total plant capacity is then:

$$X_{fgd,elec} = \frac{AEC}{1000 * MW_g * CF * 8760} . \qquad \text{[Eq 79]}$$

Total energy cost then follows directly from knowledge of the plant size, the capacity factor, and the unit cost of electricity, as discussed earlier for particulate control devices.

A second major use of energy is steam for flue gas reheat. In the TVA model it is assumed that plant steam at 470°F loses its enthalpy of evaporation (751 Btu per pound) in a heat exchanger, raising the scrubber exit gas temperature from approximately 125°F to 175°F before its final exhaust to the atmosphere through the stack. The energy required can be determined through an energy balance on the system. The critical parameters are the total gas flow rate and the fraction of gas bypassing the scrubber.

Assuming an inlet gas temperature of 300°F and 50°F reheat of scrubbed gas gives:

$$ASC = 499 * CF * G\,(1 - 3.5f_{byp}) \qquad \text{[Eq 80]}$$

where $ASC =$ annual steam consumption (lbs)

$CF =$ capacity factor (fraction)

$G =$ total flue gas flow (acfm @ 300°F)

$f_{byp} =$ fraction of gas bypassing scrubber

Equation 80 indicates that no reheat is necessary if the emission regulation allows more than 28.5 percent of the gas to be bypassed for the coal being burned. Below this value, the steam energy consumption is the steam mass rate times the enthalpy of evaporation. If the boiler efficiency (the heat delivered to steam per unit of fuel energy input) is assumed to be 85 percent, the total primary annual steam energy required can be expressed as an equivalent electrical penalty using the plant heat rate to convert fuel energy rate to plant capacity. The result is

$$(ASC)_{elec} = 442{,}100 * CF * G\,(1 - 3.5f_{byp})/HR \qquad \text{[Eq 81]}$$

where $(ASC)_{elec}$ is the equivalent annual electricity consumption for reheat, in kilowatt hours. Equation 79 can then be used to express this as a fraction of total plant capacity. Costs again follow directly, knowing the unit electricity cost.

Although this model expresses steam energy as an equivalent capacity penalty, the economic results are nearly identical to those implied by the TVA model, which utilizes separate unit costs for steam and electricity. TVA assumes that FGD electricity use costs 3.7 cents per kilowatt hour and that steam costs \$2.50 per 1000 pounds (similar to the EPRI values for January 1981 of 3.5 cents per kilowatt hours and \$2.50 per 1000 pounds [46]). Steam cost is converted to equivalent coal cost assuming 751 Btu per pound of steam and an 85 percent boiler efficiency. This gives \$3.91 per million Btu of fuel. Alternatively, the equivalent electricity cost can be obtained by multiplying this fuel cost by the plant heat rate. Assuming 9500 Btu per kilowatt hour gives an equivalent electricity cost for steam of 3.7 cents per kilowatt hour. Thus, the TVA model implicitly assumes identical costs for both steam and electricity, subject to slight variations for different plant heat rates.

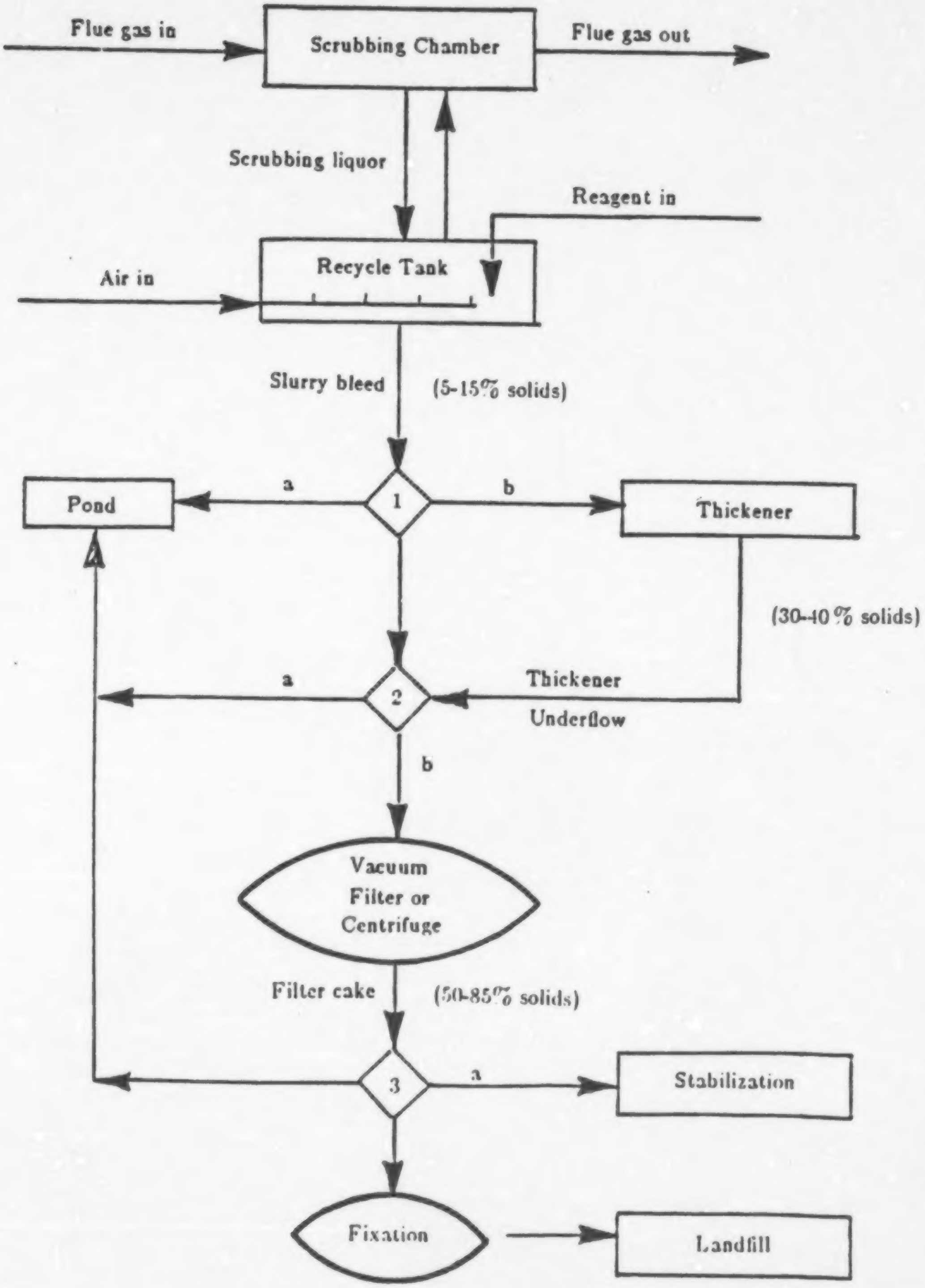
The value of electricity costs suggested by TVA and EPRI is only about half the typical average electricity costs calculated for new coal-fired power plants with FGD. In essence, this assumes that a new plant can "buy" electricity from existing plants at a lower average price. Applying the full (marginal) cost of new plant capacity would give substantially higher utility costs for environmental control. As noted earlier, a user-specified electricity price is adopted in the AUSM, with a default value of 5.5 cents/KWh reflecting a price between current costs and the replacement cost of lost capacity.

5.2.6.5 Solid Waste Disposal.

5.2.6.5.1 **Overview**. The capital cost of a solid waste disposal system can be expected to depend principally on the mass rate of waste generation. The cost of land is another factor that has been modeled separately for accounting convenience. The capital costs are scaled on full capacity SO_2 and ash removal rates, although the assumed lifetime volume of solids collected reflects a 30-year life with a nominal declining capacity factor. Models have been developed for two options: forced oxidation with gypsum landfill, and simple untreated ponding of solid wastes. Forced oxidation with gypsum landfill is assumed as the AUSM default option. The capital cost models were developed using multiple regression analysis of the solid waste disposal costs reported by the Tennessee Valley Authority [34] and the execution of the July 1982 version of the TVA lime/limestone computer model. The total variable cost of solid waste disposal is modeled on the basis of average annual SO_2 and flyash removal rates.

5.2.6.5.2 **Process Options**. Treatment options for FGD waste are represented in Figure 5-11. The slurry bleed contains from 5 to 15 percent solids consisting of calcium sulfate ($CaSO_4 * 2\ H_2O$), calcium sulfite ($CaSO_3 * 1/2H_2O$), and limestone ($CaCO_3$). The relative proportion of these constituents depends on the extent to which oxidation of calcium sulfite to calcium sulfate has occurred and on the amount of excess reagent. By mixing air with the slurry, oxidation to about 90 percent calcium sulfate is possible. Without such forced oxidation the relative amounts of the two sulfur products are about equal. All equipment and operations beyond the slurry bleed are regarded as part of the waste disposal system. Operations up to and including the slurry bleed constitute the scrubbing system.

Figure 5-11
SOLID WASTE OPTIONS FOR FGD SLUDGE


Flue gas in
Scrubbing Chamber
Flue gas out
Scrubbing liquor
Reagent in
Recycle Tank
Air in
Slurry bleed
(5-15% solids)
a
1
b
Pond
Thickener
(30-40 % solids)
a
2
Thickener
Underflow
b
Vacuum
Filter or
Centrifuge
Filter cake
(50-85% solids)
3
a
Stabilization
Fixation
Landfill

Waste disposal option 1a (see Figure 5-11) is ponding. The slurry bleed is simply pumped to a settling pond without treatment. Option 2a is ponding after thickening to 30 to 40 percent solids. Either option can be used with or without forced oxidation, but forced oxidation generally precedes dry disposal. Two fundamentally different dry disposal options are available, fixation and stabilization. Prior to the application of a fixation or stabilization technique, the slurry is further dewatered via vacuum filter or centrifuge to between 50 and 85 percent solids. The higher value is obtained only with highly oxidized sludge.

Option 3a, stabilization, is primarily a mechanical process by which the "quicksand-like" instability of wet sludge is remedied. For unoxidized sludge this requires the addition of dry flyash to yield a combined product with about 75 percent solids. Because of the greater inherent stability of oxidized sludge and its superior dewatering characteristics, flyash blending is not required to stabilize oxidized sludge.

If alkaline flyash is used for stabilization, pozzolanic reactions occur converting the mixture to cement-like material. This chemical process is called fixation. It is more commonly accomplished by the addition of lime or other reagent (with or without flyash). Two proprietary fixation processes are Dravo "Calcilox" and IUCS "Poz-O-Tec." The fixation processes are relatively expensive but may be necessary if high stability or low permeability are important.

5.2.6.5.3 **Solid Waste Emission Rates.** Solid waste production can be estimated from stoichiometric considerations. Although intermediate reactions, dissolution of solids, and absorption of gas all affect process efficiency, the overall reactions for a lime or limestone scrubber are:

1. $SO_2 + Ca(OH)_2 \xrightarrow[aq]{} CaSO_3 \cdot (1/2)H_2O$

2. $SO_2 + Ca(OH)_2 + (1/2)O_2 \xrightarrow[aq]{} CaSO_4 \cdot 2H_2O$

3. $SO_2 + CaCO_3 \xrightarrow[aq]{} CaSO_3 \cdot (1/2)H_2O + CO_2$

4. $SO_2 + CaCO_3 + (1/2)O_2 \xrightarrow[aq]{} CaSO_4 \cdot 2H_2O + CO_2$

Reactions 1 and 3 produce calcium sulfite (hemihydrate), while Reactions 2 and 4 produce calcium sulfate (dihydrate). The relative amounts of each depend on process characteristics. Calcium sulfate is the more desirable product, and most processes strive to oxidize the sulfur and produce this product. The fraction of sulfur in the product present as sulfate is referred to as the extent of oxidation, O_x:

$$O_x = \frac{N(SO_4)}{N(SO_4) + N(SO_3)} \qquad \text{[Eq 82]}$$

where $N(SO_4) =$ number of lb-moles $CaSO_4 * 2H_2O$ (mol. wt. = 172)

$N(SO_3) =$ number of lb-moles $CaSO_3 * 1/2\ H_2O$ (mol. wt. = 129)

The total mass of dry sulfur solids, m_{sul}, is

$$m_{sul} = 172 * N(SO_4) + 129 * N(SO_3). \qquad \text{[Eq 83]}$$

By Equation 80, however,

$$N(SO_3) = N(SO_4)\,(1 - O_x)/O_x\,. \qquad \text{[Eq 84]}$$

Therefore,

$$m_{sul} = [172 + 129\,\frac{1 - O_x)}{O_x}] * N(SO_4). \qquad \text{[Eq 85]}$$

Since each mole of SO_2 absorbed produces either sulfite or sulfate,

$$N(SO_2) = N(SO_4) + N(SO_3) \qquad \text{[Eq 86]}$$

where $N(SO_2)$ is the number of moles of SO_2 removed by the scrubber.

Using Equations 83 and 84,

$$\begin{aligned} N(SO_2) &= N(SO_4)\,[1 + (1 - O_x)/O_x] \\ &= N(SO_4)/O_x \qquad \text{[Eq 87]} \\ N(SO_4) &= N(SO_2) * O_x \qquad \text{[Eq 88]} \end{aligned}$$

Substituting into Equation 85,

$$m_{sul} = \dot{N}(SO_2)[172 + 129 * (1-O_x)/O_x] * O_x$$

$$= \dot{N}(SO_2)[172 * O_x + 129 * (1-O_x)] \qquad \text{[Eq 89]}$$

The mass rate of solids production, $\dot{m}_{sul}$, is found noting that

$$\dot{N}(SO_2) = \frac{S}{64} \; (\textit{ton-moles per hour}), \qquad \text{[Eq 90]}$$

where S is the sulfur dioxide removal rate in tons per hour. Using these definitions gives:

$$\dot{m}_{sul} = \frac{S}{64} \; [172\; O_x + 129\; (1 - O_x)]. \qquad \text{[Eq 91]}$$

Therefore, for a given extent of oxidation the solids production is linearly related to the SO_2 removal rate.

It is common to use more reagent than is actually required stoichiometrically. Typically, about 30 percent excess reagent is used for limestone systems and 10 percent excess reagent is used for lime systems. If R_x is the excess reagent on a mole basis, the rate of excess reagent disposal is

$$\dot{R}_x = \frac{S}{64} * R_x \; (\textit{ton-moles per hour}). \qquad \text{[Eq 92]}$$

The mass rate of unreacted reagent disposal, $\dot{m}_x$, in tons per hour is

$$\dot{m}_x = \dot{R}_x * (\textit{mol. wt. of reagent}). \qquad \text{[Eq 93]}$$

Note also that R_x is related to the total molar stoichiometric ratio (MSR) by the identity

$$R_x = MSR - 1. \qquad \text{[Eq 94]}$$

The molecule weight of limestone (calcium carbonate) is 100. With lime, CaO, calcium hydroxide is quickly formed and converted to calcium carbonate so the reagent is effectively $CaCO_3$. Because all these compounds are only slightly soluble, the mass of aqueous reagent and product is ignored. The total amount of solids generated is the sum of excess reagent, calcium sulfate, calcium sulfite, and flyash removed. Using Equation 91 and converting moles to mass gives

$$m_{tot} = \frac{S}{64} \; [100 * R_x + 172 * O_x + 129 * (1 - O_x)] + A$$

$$= S(100 * R_x + 43 * O_x + 129)/64 + A$$

$$= S(WSR + 0.672\ O_x + 0.453) + A \qquad \text{[Eq 95]}$$

where $m_{tot} =$ dry mass rate of total solids generation (tons/hr)

$S =$ mass rate of SO_2 removal (tons/hr)

$O_x =$ extent of oxidation to $CaSO_4 \cdot 2H_2O$

$WSR =$ weight stoichiometric ratio (from Equation 70)

$A =$ mass rate of ash removal (tons/hr)

The total solids production is linearly related to the sulfur dioxide removal rate, and the slope is determined by the extent of oxidation (a model parameter) and fraction of excess reagent. If chemical stabilization is used, the additional mass of additive also must be considered, though in general this does not appreciably change the total mass.

Finally, the dry solids production is related to total (wet) solid waste production by the weight fraction moisture. Thus,

$$SW = m_{tot}/f_{sol} \qquad \text{[Eq 96]}$$

where f_{sol} is the fraction of dry solids in the scrubber sludge. This too is a model parameter which depends on the dewatering level of the process selected.

The equations above are used in the AUSM to calculate the mass of solid waste disposal from a wet FGD system. The cost of this disposal, however, is calculated from other algorithms described below.

5.2.6.5.4 **Capital Cost Models.** This section reviews the development of economic models for solid waste disposal. Again, detailed studies performed by the Tennessee Valley Authority provide the basis for these simplified models. The early work of TVA (in the mid to late 1970s) first focused on disposal of untreated FGD wastes and flyash, then incorporated several commercial process options for FGD sludge fixation. More recently, landfill disposal of oxidized FGD sludge (gypsum) has been analyzed; this is the currently preferred option for new facilities.

A characteristic of the TVA cost estimates is that the predicted real cost of waste disposal has increased dramatically over time. This is seen in Figure 5-12, which shows the direct capital cost (excluding land) of two options reported by TVA in different years. When adjusted to a common basis of 1981 dollars (using the CE cost index), two- to four-fold cost increases are seen for the four-year period shown.

To capture this increase in cost, our models for ponding and gypsum-landfill-waste-disposal direct capital cost recently have been revised, based on executions of the most recent version (July 1982) of the TVA lime/limestone computer model. The parameters varied in the 36 cases which were utilized are shown in Table 5-10.

In general, for a fixed plant lifetime, the capital cost of solid waste disposal systems can reasonably be expected to depend primarily on the quantity (or rate) of waste disposal. Thus, our cost equations are based on the same ash and sulfur dioxide removal rates that were used in the scrubber module cost models. The general form of the waste disposal cost then becomes:

$$DCC_{wd} = k + f_1\, S^a + f_2\, A^b + LC \qquad \text{[Eq 97]}$$

where $DCC_{wd} =$ waste disposal direct capital cost (million \$1981)

$S =$ SO_2 removal rate (tons/hr)

$A =$ ash removal rate (tons/hr)

$LC =$ land cost (million \$1981)

and k, f_1, f_2, a, and b are constants.

For untreated ponding this becomes

$$DCC_{pd} = 1.58 + 1.95\, S^{0.8} + 1.02\, A^{0.7} + LC\, (R^2 = 99.3\%,\ d.f. = 33) \qquad \text{[Eq 98]}$$

where $LC =$ $ULC\,(0.0348\, S^{0.806} + 0.0146\, A^{0.7})$

$ULC =$ *unit land cost* (\$1000/*acre*)

For the gypsum/landfill option,

$$DCC_{lf} = 2.12 + 0.818\, S^{0.8} + 0.496\, A^{0.6} + LC\, (R^2 = 99.1\%,\ d.f. = 33) \qquad \text{[Eq 99]}$$

Figure 5-12
ESCALATION OF WASTE DISPOSAL DIRECT CAPITAL COST
(without land; TVA values)

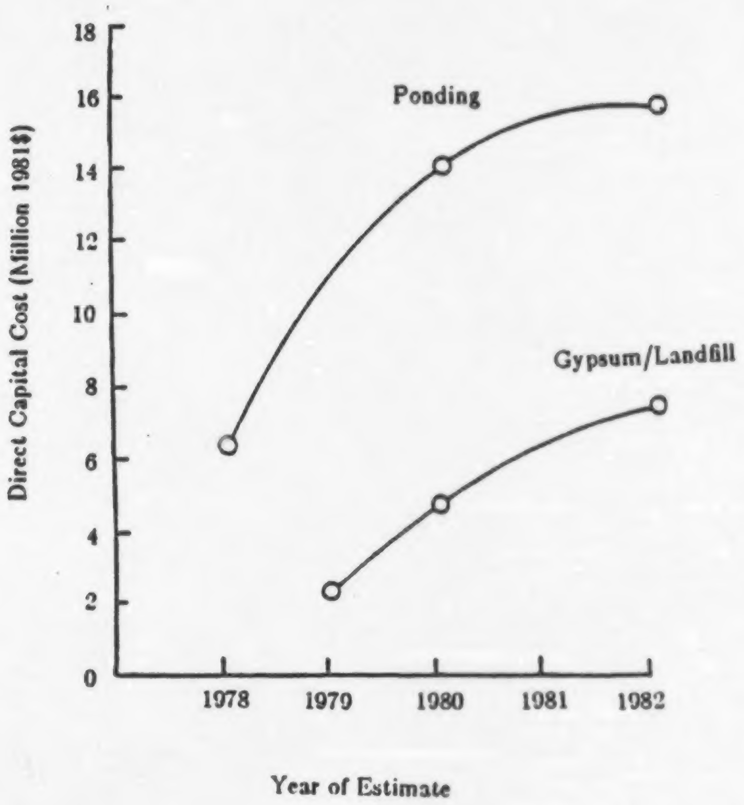


Table 5-10
CASE STUDIES FOR WASTE DISPOSAL

Parameter	Variation
Plant size (MW)	200, 500, 1000
Coal sulfur content (%S)	0.25, 0.5, 1, 2, 3, 4
Ash disposal in sludge	All cases with and without

where $LC = ULC\,(0.006611 + 0.008069\ SW^{0.7})$

$SW =$ mass of solids removed (tons/hr, Eq 96)

The predicted waste disposal costs are for on-site disposal or local disposal (for the case of landfill one mile from the plant) of either the FGD sludge alone or a blend of sludge or flyash. The land costs have been separated from other direct costs for accounting convenience; they were derived from an earlier TVA study [19]. Total capital cost is calculated as before, except that land costs are not multiplied by the indirect cost factor. The nominal indirect cost factor, based on TVA studies, is 0.55 for ponding and 0.75 for landfill. Removing AFUDC reduces these to 0.36 and 0.53.

5.2.6.5.5 **Variable Cost Models.** The variable cost model for untreated ponding waste disposal system is also based on estimates from TVA [34]. A regression performed on those estimates for the 10 conditions listed in Table 5-11 yields

$$TVC = 0.44 + 0.0484(S * CF)^{0.67} + 0.0138(A * CF)^{0.65} \qquad [\text{Eq } 100]$$

where $TVC =$ total variable cost (10^6 1981\$)

$S =$ SO_2 removal rate (tons/hr)

$A =$ ash removal rate (tons/hr)

$CF =$ plant capacity factor (fraction)

Table 5-11
CASE STUDIES FOR THE PONDING VARIABLE COST MODEL

Case Number	Variation	Case Number	Variation
1	Base[a]	6	2% sulfur
2	200 MW	7	5% sulfur
3	1500 MW	8	200 MW, no flyash
4	12% ash	9	1500 MW, no flyash
5	20% ash	10	no flyash

[a] *The base case is a 500 megawatt plant using 3.5 percent sulfur coal with 16 percent ash.*

Variable costs for the gypsum/landfill process were modeled from a later TVA study [35] since they were not presented in the study used for untreated ponding. A regression analysis performed on the data gave good correlation ($R^2 = 98.7$, d.f. $= 4$) with the equation:

$$TVC = 1.205 + 0.146\,(S * CF)^{0.7} + 0.09\,(A * CF)^{0.5} \qquad \text{[Eq 101]}$$

where all symbols are as defined for Equation 100.

5.2.6.6 **Summary of Cost and Performance Models**

Tables 5-12 and 5-13 summarize the key algorithms used to calculate pollution control capital costs and variable costs for particulate and wet FGD removal systems. (Nomenclature for these tables appears in Table 5-14.) These algorithms are used in Equations 1 and 2 to calculate total capital cost and annual revenue requirement (excluding utilities), respectively. The fixed charge factor is supplied from calculations discussed in Section 5.2.9. Auxiliary energy costs are given by Equation 48, using the appropriate power penalty for each technology.

Note that costs in Tables 5-12 and 5-13 are reported in 1981 dollars. The AUSM, however, reports costs in constant 1980 dollars (the base year for all scenarios). As discussed earlier, pollution control costs from 1980 to 1981 are adjusted using the Chemical Engineering Plant Index [2]. The appropriate values are 261.2 for 1980 and 297 for 1981. Thus, the 1980 costs reported by the AUSM are 0.8795 times the 1981 costs calculated from the equations shown here.

5.2.7 Economic and Performance Models for a Lime Spray Dryer FGD System

5.2.7.1 **Overview.** A model of a lime spray dryer FGD system (dry FGD) has been developed that contains the same basic modules of (1) material preparation and handling, (2) scrubber trains, and (3) solid waste disposal as the wet limestone FGD system model described previously. The principal difference is in the scrubber module. For a dry FGD system, a relatively small quantity of liquid slurry with a typical liquid-to-gas ratio of 0.3 gallons per thousand actual cubic feet (gal/macf) is atomized as the flue gas passes through the scrubber module concurrently with the spray. Chemical reactions occur between the evaporating absorbent and sulfur dioxide (SO_2) in the flue gas. By careful control of the slurry droplet size, and absorber design, the droplets evaporate by the time they reach the bottom of the spray tower (a process very similar to that used to make powdered milk or instant tea). These particles are entrained in the gas flow and transported from the scrubber to a particular control device, nominally a fabric filter, where they are removed along with flyash. This contrasts with a wet FGD system, where a large quantity of absorbent slurry (typical liquid-to-gas ratio of 90 gal/macf) completely saturates the flue gas stream in counter-current flow, and the reaction products of SO_2 and absorbent are removed from the scrubber as part of a slurry. In the wet FGD system, flyash also may be removed in the slurry, but it is usually removed upstream of the scrubber module by an electrostatic precipitator or fabric filter.

In contrast to wet limestone FGD, a dry lime system produces a dry solid waste instead of a thickened sludge. This solid waste can be used as a partial recycle slurry to reduce alkali reagent costs.

Dry FGD systems on coal-fired power plants are only now emerging at a commercial scale in the United States; hence, detailed and reliable data on system design, performance, and costs are not as widely available as for wet FGD systems. In particular, the use of dry FGD systems thus far has been limited to low-sulfur western coal applications and moderate SO_2 removal efficiencies, where the

Table 5-12

DIRECT AND VARIABLE COST OF SELECTED POWER PLANT COMPONENTS[a]

(Millions of 1981 dollars)

Component/Option	Total Direct Cost (TDC)	Variable Cost (Excluding Utilities)
Dry Flyash Collector		
1. Cold-side ESP:	$49.64 * 10^{-6} * (AR_{esp})^{0.81} + 6424 * MW_g$	$12.13 * 10^{-6} * CF * AR_{esp}$
2. Hot-side ESP:	$22.56 * 10^{-6} * (AR_{esp})^{0.87} + 6424 * MW_g$	$12.13 * 10^{-6} * CF * AR_{esp}$
3. Fabric filter:	$39.86 * 10^{-6} * (AR_{ff})^{0.84} + 6424 * MW_g$	$2621 * CF * MW_g + AR_{ff} * (BAG/BL) * 10^{-6}$
Limestone FGD System		
Materials Handling		
1. CAP < 18:	$0.1323 * CAP + 2.859$	(included below)
2. CAP ≥ 18:	$0.07288 * CAP + 5.393$	(included below)
+		
Scrubber trains		
1. With forced oxidation:	$(NDP + NSP) [2.892 + (0.0422 * S + 1.12 * 10^{-6} * G) / NOP]$	$CF * 10^{-3} * [8.76 * CAP * RC + 135 * S + 0.00345 * G + 1890]$
2. Without forced oxidation:	$(NDP + NSP) [2.781 + (0.0406 * S + 1.08 * 10^{-6} * G) / NOP]$	$CF * 10^{-3} * [8.76 * CAP * RC + 130 * S + 0.00332 * G + 1820]$
Solid Waste Disposal		
1. Untreated ponding: land + process	$LC [0.0348 * S^{0.806} + 0.0146 A^{0.7}]$ $+ 1.58 + 1.95 * S^{0.8} + 1.02 * A^{0.7}$	$0.0484 (S*CF)^{0.87} + 0.0138 (A*CF)^{0.88} + 0.44$
2. Gypsum landfill: land + process	$LC [0.00661 + 0.008069 * SW^{0.7}]$ $+ 2.12 + 0.818 * S^{0.8} + 0.496 * A^{0.6}$	$0.146 (S*CF)^{0.7} + 0.09 (A*CF)^{0.6} + 1.205$

[a] Applies to new plants only

Table 5-13
ESTIMATION OF PHYSICAL PARAMETERS FOR THE POWER PLANT COST MODELS[a]

Parameter	Estimating Equation
Pollutant Removal Efficiencies	
η_{TSP}	$1 - [(HV * EC_a * 10^{-4})/(f_c^a * \%A)]$
η_{SO_2}	$1 - [(HV * EC_s * 10^{-4})/(2f_c^s * \%S)]$
Plant Flow Rates	
A	$[(\%A * f_c^a * 10^4/HV) - EC_a]\,[HR * MW_g/(2 * 10^6)]$
S	$[(2 * f_c^s * \%S * 10^4/HV) - EC_S]\,[HR * MW_g/(2 * 10^6)]$
G	$(MW)(HR)(T/760)*\{0.240 + 0.254e +$ $[(2.265 - 1.341e)(100 - \%A - \%m) + (5.140)(\%m)]/HW\}$
f_{bps}	$1 - (\eta_{SO_2}/\eta_{FGD})$
	[For full scrubbing (no bypass) $\eta_{FGD} = \eta_{SO_2}$]
$\hat{G}$	$G\,(1 - f_{bps})$
SW	$[S(WSR + 0.672\,O_x + 0.453) + A]/f_{sol}$
Component Energy Requirements	*(Fraction of Gross Plant Capacity)*
$\chi_{cold\ esp}$	$[1.5 * 10^{-6}\,(AR_{esp}) + 1.55 * 10^{-7} * G_{cold}]/MW_g$
$\chi_{hot\ esp}$	$[1.9 * 10^{-6}\,(AR_{esp}) + 1.55 * 10^{-7} * G_{hot}]/MW_g$
χ_{ff}	$(9.28 * 10^{-7} * G_{cold} * (2.0/AC)^{2.5})/MW_g$
$\chi_{fgd,elec}$ with forced oxidation	$[(1 + 0.035 * \%S)\,(0.322 + 0.217S + 4.20 * 10^{-6}\,G)]/MW_g$
$\chi_{fgd,elec}$ without forced oxidation	$(0.322 + 0.217S + 4.20 * 10^{-6}\,G)/MW_g$
$\chi_{fgd,reheat}$	$(5.05 * 10^{-2}G)(1 - 3.5f_{bps})/(HR * MW_g)$, for $0<f_{bps}<0.285$ $= 0$ for $f_{bps}\geq 0.285$
$\chi_{fgd,total}$	$\chi_{fgd,elec} + \chi_{fgd,reheat}$

Table 5-13 (contd.)

Parameter	Estimating Equation
Dry Collector Parameters	
T	$\approx 300^{o}F$ ($760^{o}R$) (cold ESP) $\approx 700^{o}F$ ($1160^{o}R$) (hot ESP)
AR_{esp}	$G * SCA$
	$SCA = [-\ln (1 - \eta_{TSP})]^{1.549} * (0.939/W)$
	$W = 20.$ (hot ESP) $W = 38.474/[6.396 * 10^{-16} \exp(1.382 \ln R) + 1]$ (cold ESP) (minimum = 20)
	$R = \exp(6.98 - 1.36\%S)[(\exp(-0.02075 * \%S^{1.2158})] + 20.723$
AR_{ff}	G/AC
	$AC = 1.7 + 100 * (OL)$ $(1.8 < AC < 3.0)$
	$OL = [(1/\eta_{TSP}) - 1] * (AC)\ 2.33 * 10^{5}$ (maximum = 0.003)
BL	$4.0 - AC$ $(1.8 < AC < 3.0)$
FGD System Parameters (Limestone Scrubbing)	
CAP	$S * WSR$
WSR	$1.72 + 25.5 (\eta_{FGD} - 0.67)^{2.5}$, for $0.7 \leq \eta_{FGD} \leq 0.95$
	1.72 for $\eta_{FGD} < 0.7$
NOP	$(1 - f_{bps}) * MW_{g}/125$ (nearest integer)
NSP	NOP/4 (minimum = 1) (truncated integer)

[a] *Values of these parameters specified by other means can still be used with Table 5-13.*

Table 5-14

NOMENCLATURE FOR TABLES 5-12 AND 5-13

A = flyash removal capacity (tons/hr)

AC = fabric filter air-to-cloth ratio (acfm/ft^2)

AR_{esp} = electrostatic precipitator collector area (ft^2)

AR_{ff} = fabric filter surface area (ft^2)

%A = ash in as-fired coal (percent)

BAG = fabric filter bag cost ($/$ft^2$)

BL = fabric filter bag life (years)

CAP = scrubber reagent capacity (tons/hr)

CF = annual plant capacity factor (fraction)

e = excess air, including leakage (fraction)

EC_a = flyash emission constraint (lb/10^6 Btu)

EC_s = sulfur dioxide emission constraint (lb/10^6 Btu)

f_a = fraction of ash entering flue gas stream

f_{bps} = fraction of flue gas not scrubbed

f_s = fraction of sulfur entering flue gas stream

f_{sol} = fraction of solids for M_{sol}

G = flue gas flow rate at full capacity (acfm)

$\hat{G}$ = flue gas flow rate capacity through scrubber (acfm)

HR = gross cycle heat rate (Btu/KWh)

HV = coal higher heating value, as received (Btu/lb)

LC = waste disposal land cost (10^3 $/acre)

%m = percent moisture in as-fired coal

M_{sol} = mass of solids for disposal (tons/hr)

MSR = molar stoichiometric ratio (moles reagent/mole SO_2)

MW_g = gross power plant capacity (megawatts)

η_{FGD} = specified scrubber removal efficiency (fraction)

NOP = number of operating scrubber trains (integer)

NSP = number of spare scrubber trains (integer)

OL = fabric filter outlet loading (grain/scf)

O_x = oxidation of calcium sulfite to calcium sulfate

R = flyash resistivity (ohm-cm)

RC = scrubber reagent cost ($/ton)

Table 5-14 (contd.)

RSD = relative standard deviation of sulfur in coal (dimensionless)
S = scrubber SO_2 removal capacity (tons SO_2/hr)
SCA = specific collection area (ft^2/acfm)
%S = sulfur in as-fired coal (percent)
T = flue gas temperature at device inlet (^oR)
W = particle drift velocity (ft/min)
WSR = weight stoichiometric ratio (lb reagent/lb SO_2)
X = energy requirement (fraction of plant capacity)

economics of dry FGD is most favorable. Though design studies also are available for high sulfur coal applications and high SO_2 removal efficiencies, full-scale data remain lacking. Nonetheless, the analytical model of a dry FGD system incorporated in the AUSM may be easily used in sensitivity studies to explore the consequences of alternative assumptions regarding the nature or impacts of future developments.

Development of the dry FGD model was based on a number of recent studies [31,59-74]. Tennessee Valley Authority (TVA) data and assumptions were used as extensively as possible to maintain consistency between the wet and dry FGD system models in the AUSM. However, care was taken to ensure that model parameters also could reflect alternative design and cost assumptions. The following sections describe the cost and performance models of the three major components of the dry FGD system model.

5.2.7.2 **Performance Model.** The dry FGD system is assumed to be capable of removing up to 90 percent of the inlet SO_2 to the scrubber. The nominal operating efficiency is 70 percent; bypass is allowed should an emission standard permit the use of partial scrubbing. As with the wet FGD system, the reagent stoichiometry required to achieve a given SO_2 removal efficiency is the key performance parameter in the AUSM. As noted earlier, commercial systems in the United States to date have been limited to low sulfur coals (typically 0.8 percent sulfur or less), with removal efficiencies typically in the range of 70 to 75 percent [59]. Many of these systems use sub-bituminous coals with significant alkaline ash content that reduces the need for added reagent. Thus, reliable specification of reagent stoichiometry over a full range of possible utility coals and performance requirements is not yet available. Data from pilot plants and small-scale applications currently provide the principal basis for evaluating performance at higher removal efficiencies and higher sulfur contents typical of many bituminous coals [59,61,63-66,72].

When discussing dry FGD, it is customary to define reagent stoichiometry as the ratio of reagent (lime) used per unit of SO_2 entering the scrubber. This definition is slightly different from that used with wet FGD systems. There, the stoichiometric ratio is based on the amount of SO_2 removed. For dry FGD systems, the relationship between stoichiometry and SO_2 removal efficiency is most affected by the extent of solids recycling, the flue gas temperature, and the flue gas moisture content [59,63]. The inlet SO_2 concentration also is a factor, but this effect appears to be small relative to other factors [63]. For the AUSM, experimental data for a 20 degrees F. approach to flue gas saturation [64] was utilized to estimate the molar stoichiometric ratio (MSR) as a function of SO_2 removal efficiency:

$$\begin{aligned} MSR &= 1.1 \ (\eta_{SO2} \leq 0.70) \\ & \quad 2.57 \ \eta_{SO2}^{2.38} \quad (0.70 < \eta_{SO2} \leq 0.90) \end{aligned} \qquad \text{[Eq 102]}$$

where

η_{SO_2} = SO_2 removal efficiency (fraction)

MSR = molar stoichiometric ratio (moles reagent/$mol\ SO_2$ input).

This relationship is plotted in Figure 5-13. Results are consistent with other recent studies [67,70,71]. Alternative relationships also can easily be substituted in the AUSM to test the sensitivity of model results to performance assumptions, or to improve upon the current model as additional data become available.

5.2.7.3 Direct Capital Cost Models

5.2.7.3.1 Materials Handling and Preparation. The model of materials handling and preparation cost is based on 30 executions of the TVA Wet Lime FGD Model [31]. The parameters that were varied and the results of each run are shown in Table 5-15. The TVA model was used since wet and dry lime FGD systems share the same basic materials handling and preparation operation. A piecewise linear curve

Figure 5-13

DRY FGD REAGENT STOICHIOMETRY

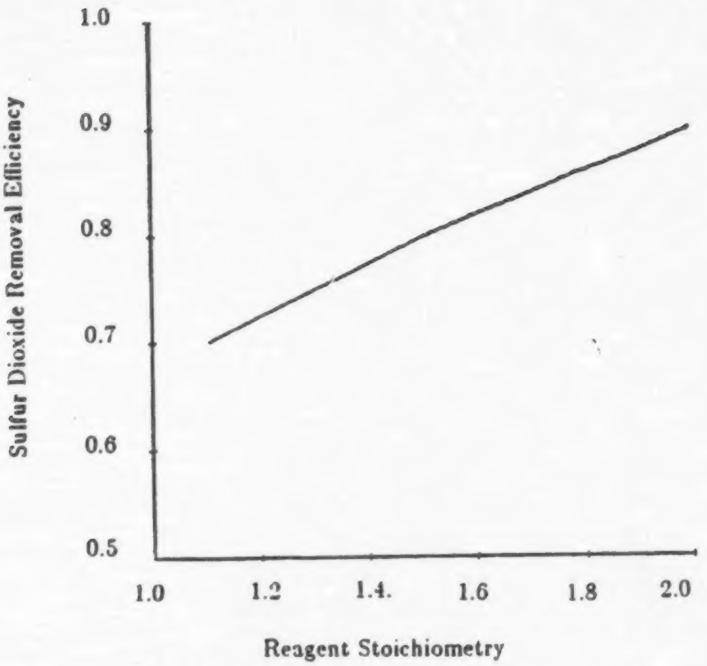


Table 5-15

TVA MODEL DATA UTILIZED IN THE LIME MATERIAL HANDLING AND PREPARATION MODEL

Run	Plant Size (MW)	Coal Sulfur (Percent)	Reagent Capacity (TPH)	DCC (million 1981$)
1	125	0.5	0.3818	1.613
2	125	1.0	0.7273	1.778
3	125	1.5	1.1636	1.863
4	125	2.0	1.6727	1.997
5	125	2.5	2.6545	2.454
6	125	3.0	0.7636	1.828
7	250	0.5	1.4545	1.975
8	250	1.0	2.3455	2.424
9	250	1.5	3.3273	2.625
10	250	2.0	5.3273	2.956
11	250	2.5	1.1455	1.913
12	250	3.0	2.1636	2.409
13	500	0.5	3.5091	2.683
14	500	1.0	5.0	2.934
15	500	1.5	7.9818	3.603
16	500	2.0	1.5455	2.057
17	500	2.5	2.8909	2.603
18	500	3.0	4.6909	2.927
19	750	0.5	6.6727	3.442
20	750	1.0	10.6364	4.015
21	750	1.5	2.3091	2.538
22	750	2.0	4.3455	2.936
23	750	2.5	7.0364	3.750
24	750	3.0	10.0	4.009
25	1000	0.5	15.9636	5.122
26	1000	1.0	3.0727	2.805
27	1000	1.5	5.7818	3.475
28	1000	2.0	9.3818	4.050
29	1000	2.5	13.3455	4.927
30	1000	3.0	21.2727	6.163

was developed using ordinary least squares linear regression of the TVA data for direct capital cost as a function of the reagent handling capacity. The result was:

$$DCC = \begin{array}{ll} 1.546 + 0.2997 * CAP & (CAP < 2.0), (R^2 = 91.6;\ d.f. = 6) \\ 2.042 + 0.1986 * CAP & (CAP > 2.0), (R^2 = 98.5;\ d.f. = 20) \end{array} \qquad \text{[Eq 103]}$$

where

DCC = direct capital cost of materials handling and preparation (10^6 1981 \$)

CAP = Reagent handling system capacity (tons lime/hr).

As with the wet FGD system, CAP is calculated from the identity:

$$CAP = WSR * S \qquad \text{[Eq 104]}$$

where,

S = SO_2 removal rate capacity (tons/hr)

WSR = weight stoichiometric ratio (lb reagent/lb SO_2 removed).

The weight stoichiometry follows directly from the molar stoichiometry, given the molecular weights of lime (56) and SO_2 (64). Thus,

$$WSR = MSR * \frac{56}{64\eta_{SO_2}} \qquad \text{[Eq 105]}$$

$$= 0.875\ \frac{MSR}{\eta_{SO_2}}$$

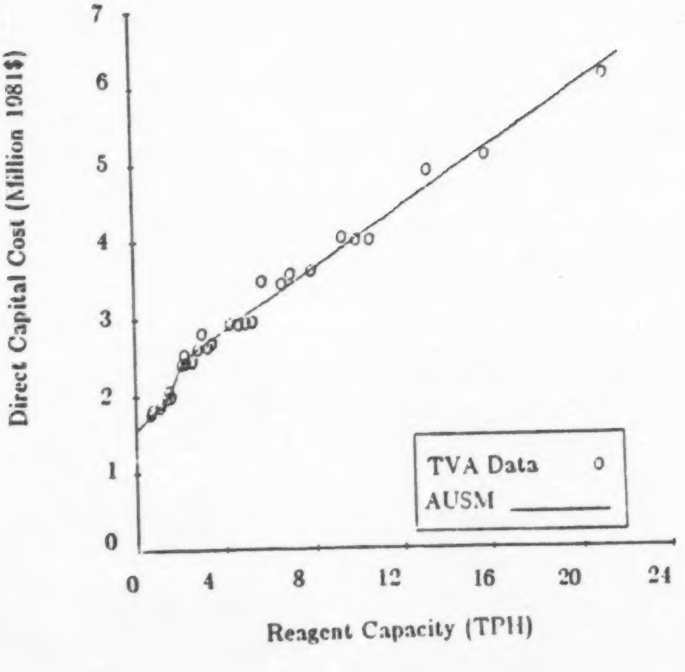
where MSR is given by Equation 102.

A plot comparing the TVA data and AUSM model is presented in Figure 5-14. The degrees of freedom (d.f.) and R^2 statistic for the regression appears with Equation 103.

5.2.7.3.2 **Scrubber Module.** Given the still developing nature of dry FGD technology, as well as the general AUSM objective of minimizing model complexity wherever possible, a simple model of scrubber capital costs was sought to permit easy substitution of alternative cost estimates by model users. Based

Figure 5-14

REGRESSION MODEL OF LIME MATERIAL HANDLING AND PREPARATION COST



on a review of several recent studies [59-74], the model adopted employs a constant cost per kilowatt of scrubber train capacity.

The scrubber module direct capital cost is based on a detailed design study conducted by TVA for the U.S. Environmental Protection Agency [59]. In this study, lime spray dryer FGD costs were estimated for four coals (lignite, low sulfur western, low sulfur eastern, and high sulfur eastern), for a plant size of 500 MW. Data for the four cases estimated by TVA is shown in Table 5-16. To determine an average cost per installed KW of a single scrubber module (nominally 125 MW), the scrubber module costs were first adjusted to obtain the cost per train (operating plus spare) as given in Column 4, Table 5-16. The individual train capacity (MW/train) was calculated by adjusting the gross capacity (500 MW) for bypass then dividing by the number of operating trains. Direct capital cost per KW of installed train capacity then follows directly. An average of the four reported capital cost values in 1982 dollars was then

Table 5-16

ESTIMATES OF LIME SPRAY DRYER DIRECT CAPITAL COST[a]

Coal Type	DCC (10^6 1982 $)	Trains (Op./Spare)	Unit Cost (10^6 $/tr.)	Bypass (Fraction)	Unit cap. (MW/tr.)	DCC (1982 $/KW)
Lignite	19.08	3/1	4.770	0.225	129.2	36.93
Low Sulfur Western	18.44	3/1	4.610	0.1875	135.4	34.04
Low Sulfur Eastern	18.13	3/1	4.533	0.1883	135.3	33.51
High Sulfur Eastern	21.70	4/1	4.340	0.0504	118.7	36.56
Mean						35.26

[a] *Reference [59].*

adjusted to a 1981 price level.[8] A value of $35.15/KW results. Utilizing the same redundant and operating train concept as employed for the wet FGD system (Section 5.2.6.2.2), and noting that the scrubbed capacity is equal to the total capacity times ($1 - f_{byp}$), the equation for dry FGD scrubber capital cost is:

$$DCC = \frac{MW(NOP + NRD)}{NOP} * 0.3515 * (1 - f_{byp}) \qquad \text{[Eq 106]}$$

where

DCC = Dry scrubber direct capital cost (million 1981$)

MW = Gross generating capacity (MW)

NOP = Number of operating trains

NRD = Number of redundant trains

f_{byp} = fraction of flue gas bypassing the scrubber.

For purposes of calculating an allowable bypass, the AUSM assumes a nominal sulfur removal efficiency of 70 percent for the dry FGD system.

5.2.7.3.3 **Solid Waste Disposal**. Solid waste disposal is assumed to be accomplished by means of a landfill. A model different from the wet FGD gypsum/landfill case (Section 5.2.6.5) was developed since the dry FGD waste does not require the solids separation and dewatering steps needed to prepare wet FGD sludge for landfill disposal. Dry FGD landfill waste disposal costs are modeled in terms of three components:

$$DCC_{WD} = DCC_{CNST} + DCC_{WH} + LC \qquad \text{[Eq 107]}$$

where

DCC_{WD} = Total direct capital cost of waste disposal

---

[8] TVA's [31] estimated 1982$ cost index of 297.9 was used with the Chemical Engineering [75] plant index for 1981$ of 297.

DCC_{CNST} = Direct capital cost of landfill construction

DCC_{WH} = Direct capital cost of waste handling

LC = Cost of land

The cost of landfill construction was estimated from the same 36 runs of the TVA model that were used in the wet FGD gypsum landfill model. Here, plant capacity was varied from 200 to 1000 MW and coal sulfur content from 0.25 to 3.0 percent with and without co-disposal of flyash. Least squares regression analysis was used to develop a relationship between total waste (FGD waste plus ash) and landfill direct capital cost:

$$DCC_{CNST} = 0.5301 + 0.1746 * SW^{0.8} \quad (R^2 = 99.8, d.f. = 34) \qquad \text{[Eq 108]}$$

where

DCC_{CNST} = Landfill construction direct capital cost (million 1981\$)

SW = Total solid waste disposal rate (tons/hour)

The land requirement was also modeled using least squares regression analysis of the same set of TVA model runs. The result was:

$$LC = ULC(6.611 + 8.069 * SW^{0.7}) \quad (R^2 = 99.9,\ d.f. = 34) \qquad \text{[Eq 109]}$$

LC = Total land cost (1981\$)

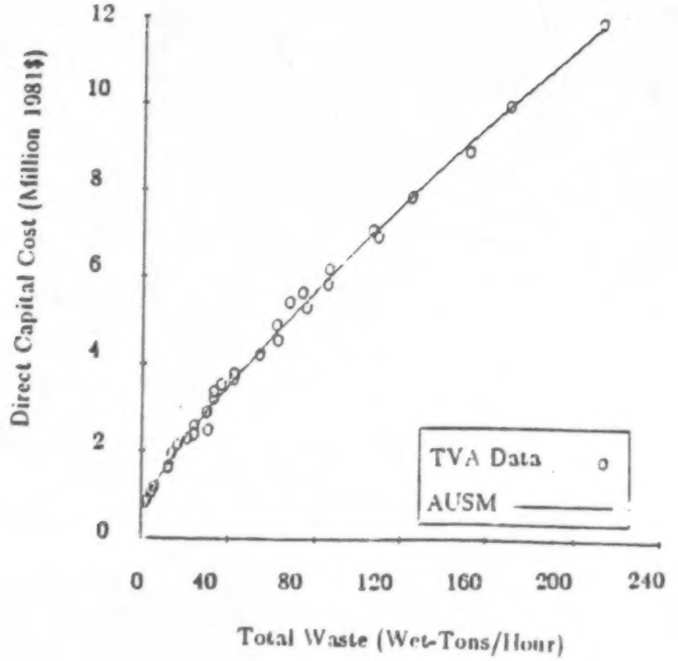
ULC = Unit land cost (1981\$/acre)

SW = Total solid waste disposal rate (tons/hour)

The regression equations above are compared to the TVA data in Figures 5-15 and 5-16, using a value of $5000/acre for land cost (the AUSM default).

Figure 5-15

REGRESSION MODEL OF LANDFILL DIRECT CAPITAL COST VERSUS WASTE QUANTITY



The solid waste disposal rate is determined in the same manner as for the wet FGD system, but the excess reagent is lime (CaO) instead of limestone ($CaCO_3$):

$$SW = [S(WSR + 0.672 * OX + 1.141) + A]/FS \qquad \text{[Eq 110]}$$

where

SW = total solid waste rate (tons/hour)

S = SO_2 removal rate (tons/hour)

WSR = weight stoichiometric ratio of reagent to SO_2 removed (see Eq. 105)

OX = oxidation of $CaSO_3$ to $CaSO_4$ (default = 0.35)

A = flyash disposal rate (tons/hour)

FS = fraction of solids in waste (default = 0.80)[9]

Solid waste handling costs were estimated using the average cost for the TVA study cases that utilized reagent recycle. In 1981 dollars, this was $3.144 million for a plant capacity of 500 MW. This amount was made a function of plant size utilizing an exponential scaling factor of 0.8, as suggested by Reference 18. The result is:

$$DCC_{WH} = 0.02179\ (MW_g)^{0.8} \qquad \text{[Eq 111]}$$

where

DCC_{WH} = direct capital cost of solid waste handling (million 1981$)

MW_g = power plant gross capacity (MW)

5.2.7.3.4 **Particulate Removal**. Entrained flyash and FGD waste is assumed to be removed from the gas stream with a fabric filter. The same fabric filter cost and performance models described earlier (Sec-

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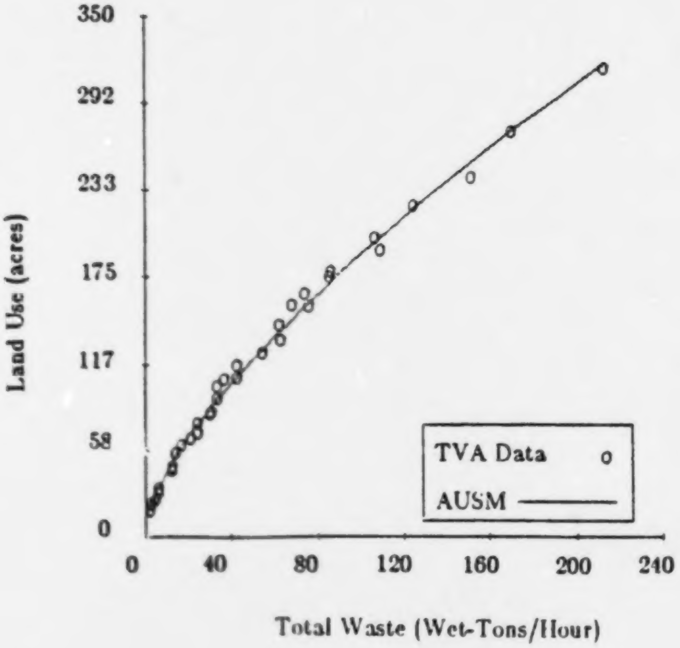
[9] Water is often added to the dry solid waste to improve its landfill disposal characteristics.

Figure 5-16
REGRESSION MODEL OF LANDFILL WASTE DISPOSAL LAND USE



tion 5.2.5) are utilized with the dry FGD system. The only default value that changes is the flue gas inlet temperature, which is assumed to be 160°F. [59], instead of 300°F. This results from the fabric filter being placed downstream of the dry FGD scrubber module instead of upstream of the scrubber module as in a wet FGD system.

5.2.7.4 **Variable Cost Models, Excluding Utilities.** Variable costs for the dry FGD are composed of reagent costs, scrubber variable costs, waste disposal costs and particulate removal variable costs. The variable cost models for waste disposal and particulate removal are unchanged from those described previously (Sections 5.2.6.5 and 5.2.5.4). Annual reagent cost is based on reagent usage and is given by:

$$ARC = CAP * 8760 * RC * CF \qquad \text{[Eq 112]}$$

where

ARC = Annual reagent cost (\$/year)

CAP = Maximum reagent capacity (tons/hour)

RC = Reagent cost (\$/ton)

CF = Annual plant capacity factor

The assumed cost of lime is a key model parameter affecting the overall cost and competitiveness of dry FGD. Values used in recent studies have varied from 50 to 95 dollars/ton in 1981 dollars [70,74]. AUSM default values are taken from TVA [59], though alternative costs may be substituted by the model user.

The dry scrubber variable cost was estimated from the same TVA study as the scrubber direct capital cost [59]. The variable costs for the four case studies were adjusted for bypass as shown in Table 5-17. The average was adjusted to an annual capacity factor of 1.0, then scaled from 1984 dollars to 1981 dollars to arrive at an annual variable revenue requirement of 9552 (1981\$/MW).[10] The elements of this cost are the same as for the wet FGD system, and include FGD operating labor and supervision, chemical analysis, process water, maintenance, and plant and administrative overhead.

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[10] TVA's [31] estimated 1984\$ cost index of 342.6 was used with the Chemical Engineering plant index [75] for 1981\$ of 297.

The algorithm used in the AUSM is:

$$VRR = 9552. * MW_t(1 - f_{byp}) * CF \qquad \text{[Eq 113]}$$

where

VRR = Dry FGD system variable revenue requirement (1981$)

MW_t = Total plant capacity (MW)

CF = Plant capacity factor

f_{byp} = Fraction of scrubber bypass

Table 5-17

ESTIMATES OF LIME SPRAY DRYER ANNUAL VARIABLE REVENUE REQUIREMENT[a]

Coal Type	VRR (10^6 1984$)	ByPass (Fraction)	VRR-500 MW (10^6 1984$)
Lignite	2.743	0.2250	3.539
Low Sulfur Western	2.660	0.1875	3.274
Low Sulfur Eastern	2.671	0.1883	3.291
High Sulfur Eastern	3.543	0.0504	3.731
Mean ± Std. Dev.	2.90±0.43		3.46±0.22

[a] *Reference [59], for a plant operating 5500 hours/year.*

5.2.7.5 **Energy Requirement and Cost Model.** Consistent with current design practice, stack gas reheat is obtained with bypass [59]. The stack gas is assumed to be reheated from 160°F to 175°F using flue gas at 300°F which requires a minimum bypass of 10.7 percent. As with wet FGD, electricity is used for pumps and fans. Electricity usage was estimated from the TVA case studies [59] in terms of the average electricity consumption per unit volume of flue gas scrubbed, as shown in Table 5-18. This average was then adjusted from standard to actual cubic feet, and to a capacity factor of unity, for use in the AUSM:

$$AEC = 39.86 * \frac{520}{760} * \frac{8760}{5500} * G\,(1 - f_{byp}) * CF$$

or,

$$AEC = 43.44 * G\,(1 - f_{byp}) * CF \qquad \text{[Eq 114]}$$

Table 5-18

ESTIMATES OF ELECTRICITY CONSUMPTION FOR LIME SPRAY DRYER FGD[a]

Coal Type	Electricity (10^6KWh/yr)	Gas Flow (10^6 acfm)	Electricity (KWh/acfm)
Lignite	43.70	1.142	38.27
Low Sulfur Western	39.57	0.075	40.59
Low Sulfur Eastern	39.41	0.940	41.93
High Sulfur Eastern	42.77	1.106	38.67
Mean ± Std. Dev.			39.86 ± 1.71

[a] *Reference [59].*

where

AEC = Annual electricity consumption (KWh/year)

G = Gas flow rate capacity to scrubber (acfm at 300°F)

CF = Plant capacity factor (fraction)

5.2.7.6 **Indirect Cost Factors**. Table 5-19 shows the indirect costs assumed for the dry FGD system model, based on the studies by TVA [31,59]. The total indirect cost factor is higher than for the wet FGD system as a result of a higher assumed contingency cost due to the more limited commercial use of dry FGD technology [31,70,71]. The nominal indirect cost factor for particulate control is also increased due to a higher contingency cost when used with dry FGD.

5.2.7.7 **Summary of Cost and Performance Models**. A summary of the dry FGD system direct cost equations is presented in Tables 5-20 and 5-21. Figures 5-17 and 5-18 show values of calculated dry FGD total capital costs and variable costs as a function of coal sulfur content for a plant meeting Revised New Source Performance Standards (RNSPS). The costs shown are the sum of costs for materials handling and preparation, scrubber module, particulate removal, and waste disposal.

5.2.8 Economic and Performance Models for Direct Limestone Injection

5.2.8.1 **Overview**. Efforts in the United States to control sulfur dioxide by the direct injection of limestone into the boiler date from the mid-1960s. At that time it was viewed as a possible alternative to the use of downstream wet scrubbing. Although pilot plant work showed possible SO_2 removal efficiencies of 45 to 60 percent, the maximum attained in commercial tests was about 25 percent. The difference was then attributed to furnace temperature as the pilot plants typically operated at 1500°F to 2100°F rather than the 2400°F to 3000°F of commercial units [77]. The concept was abandoned in favor of processes with higher removal efficiencies.

Attention has refocused recently on direct limestone injection for use with certain low NO_x combustion controls. Some of the combustion modifications that lead to reduced NO_x formation, such as

Table 5-19
INDIRECT COST FACTORS FOR A DRY FGD SYSTEM[a]

Cost Element	Dry Lime[b] FGD	Waste Disposal[b,c] Landfill	Particulate[d] Control
Engineering Design and Supervision	6-8	4-6	NA[f]
Architect and Engineering Contractor	1-3	1-2	26-19[e]
Construction Expenses	14-18	10-13	NA[f]
Contractors Fees	4-6	4-6	4
Contingency	25-27	18-19	11
Startup	15-16.2	5	NA[f]
Interest During Construction	23.4-24.0	21-23	14
Royalties	1	0	0
Working Capital	5.1-6.2	5	NA[f]
TOTAL	94.5-109.4	68-79	50-58
Representative Value, Including Interest During Construction	100	75	55
AUSM Value, Excluding Interest During Construction	78	53	41

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[a] *All factors are expressed as a percentage of Direct Capital Cost.*

[b] *Reference [59].*

[c] *Different cost factors were used by TVA for waste disposal equipment and landfill construction, since the two categories have been combined in the AUSM, average in direct cost factors are used.*

[d] *Reference [13].*

[e] *These are combined with other costs to form "Indirect Field Costs."*

[f] *Not available separately, included with Indirect Field Costs.*

Table 5-20

AUSM EQUATIONS FOR DRY LIME FGD
(Millions of 1981 dollars)

Component	Total Direct Cost	Source	Variable Cost	Source
Lime Materials Handling				
a) $CAP \leq 2$	$1.546 + 0.2997 * CAP$	[a] $R^2 = 91.6$ d.f. = 8	$CAP * CF * RC * 8760$	Derived
b) $CAP \geq 2$	$2.042 + 0.1986 * CAP$	[a] $R^2 = 98.5$ d.f. = 20		
Dry Lime Scrubber	$0.3513 * [MW_{scr} (NOP + NRD) / NOP]$	[b]	$0.009552 \ MW^{scr} * CF$	[b]
Landfill Waste Disposal				
Process	$0.5301 + 0.1746 \ SW^{0.8} + 0.02179 \ MW_g^{0.8}$	[a] $R^2 = 99.9$ d.f. = 34	$1.205 + 0.146 (S * CF)^{0.7} + 0.09 (A * CF)^{0.8}$	[c]
Land	$[LC * (6.611 + 8.096 \ SW^{0.7}) / (1*10^6)]$	[a] $R^2 = 99.9$ d.f. = 34		

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[a] From least squared regressions on runs of the TVAModel [31], see Figures 5-1 through 5-3.
[b] Calculated from Reference [59].
[c] Regression on data from Reference [35].

Table 5-21
NOMENCLATURE FOR TABLE 5-20

CAP = Reagent capacity (tons/hour)
$= MSR * S * 0.875/\eta_{SO_2}$
MSR = mole stoichiometric ratio

$$= \begin{cases} 2.57\,(\eta_{SO_2})^{2.38} & (\eta_{SO_2} > 0.7) \\ 1.1 & (\eta_{SO_2} \leq 0.7) \end{cases}$$

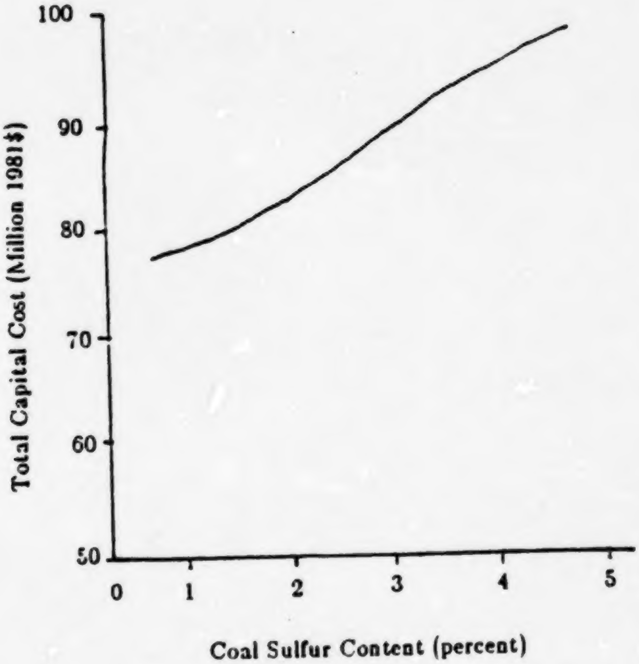
η_{SO_2} = SO_2 removal efficiency (fraction)
S = SO_2 removal rate (tons/hour)

SW = Total solid waste for disposal (wet tons/hour)
$= [S(WSR + 0.672 + OX + 1.141 + A]/FS$
WSR = Weight stoichiometric ratio
$= 0.875(MSR)/\eta_{SO_2}$
OX = Oxidation of $CaSO_4$ to $CaSO_3$ (default = 0.35)
A = Mass of flyash for disposal (tons/hour)
FS = Fraction solids in wet waste (default = 0.80)
RC = Lime reagent cost ($/ton) (default = 65)
CF = Plant capacity factor (default = 0.65)

MW_g = Gross plant capacity (MW)

MW_{scr} = Scrubbed plant capacity (MW)
$= MW_g(1 - f_{bys})$
f_{bys} = Fraction of gas not scrubbed

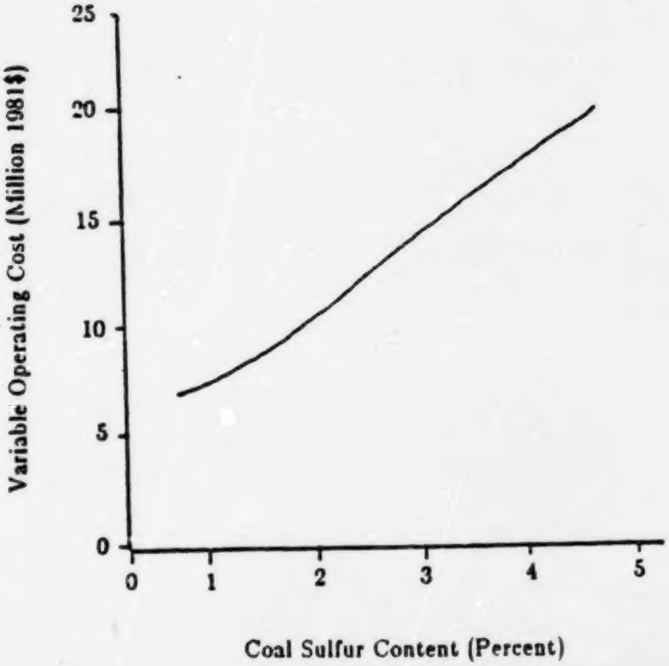
Figure 5-17
ILLUSTRATIVE RESULTS OF DRY FGD TOTAL CAPITAL COST VERSUS COAL SULFUR CONTENT



[a] Includes dry scrubber, fabric filter, and waste disposal for a 500 MW plant

Figure 5-18

ILLUSTRATIVE RESULTS OF DRY FGD VARIABLE OPERATING COST VERSUS COAL SULFUR CONTENT



[a] Includes dry scrubber, fabric filter, and waste disposal for a 500 MW plant

reducing peak flame temperature and increasing coal residence time, also improve the environment for the reaction of limestone and SO_2. Major research programs to develop direct limestone injection are being sponsored by EPA and EPRI. Reviews of past and current pilot plant results, plus engineering evaluations for commercial units, show attractive costs for SO_2 removal in the 50 to 60 percent range for both programs. The EPA program centers on combining direct limestone injection with new multistaged low-NO_x burners (LIMB) to produce a minimum of 50 percent SO_2 removal and 70 percent NO_x removal [76]. The EPRI program emphasizes combining limestone injection with less costly and more retrofitable combustion modification techniques that can be applied to existing burners to obtain similar levels of SO_2 control but half the level of NO_x control [77]. A principal goal of both programs is to provide a cost-effective alternative to the use of low sulfur coal or downstream scrubbers on pre-NSPS power plants currently burning high sulfur coal. EPA also hopes that by optimizing the various physical and chemical processes involved, SO_2 removal of 70 percent or more may be attainable, making the process viable for new boilers [76].

The basic design of the LIMB process is simple. Limestone is crushed and injected into the boiler with the coal. Here, limestone calcination takes place (Equation 115) followed by SO_2 absorption (Equation 116).

$$CaCO_3 \rightarrow CaO + CO_2 \qquad \text{[Eq 115]}$$

$$CaO + SO_2 + \frac{1}{2}\,O_2 \rightarrow CaSO_4 \qquad \text{[Eq 116]}$$

The reaction products are entrained in the gas flow and transported from the boiler where they are removed along with the coal ash by either an ESP or fabric filter. The combined solid waste is then sent to a landfill for disposal. The major advantage over other FGD processes is the elimination of a separate scrubber vessel and associated slurry handling equipment as well as the production of a dry waste (a characteristic shared with the lime spray dryer FGD). Major problems concern an insufficient understanding of CaO - SO_2 chemical reactions in the boiler and the effect of limestone on boiler operation and particulate control devices.

5.2.8.2 **Performance Model.** The relationship between reagent molar stoichiometry (moles limestone/mole SO_2 removed) and SO_2 removal efficiency is not well defined for LIMB. It is known that SO_2 removal efficiency will depend on such variables as coal properties, boiler-firing conditions, limestone reactivity, limestone fineness and limestone injection scheme, as well as reagent stoichiometry [77]. However, the precise role of these factors is not yet well understood. EPA's goal is to achieve 50 percent SO_2 removal at a reagent molar stoichiometry (MSR) of 2.0 [76]. In a recent LIMB design study by Combustion Engineering, the MSR was varied from 1.0 to 4.0 while specifying a constant removal of 50 percent [77]. TVA specified an MSR of 3.0 for 50 percent removal in their design study [78]. Due to this uncertainty in the data, the performance model selected for the AUSM is a constant stoichiometry applicable to a specified SO_2 removal efficiency (rather than a functional relationship such as that assumed for wet or dry FGD systems). For retrofit applications, a conservative default value of MSR = 3 at 50 percent SO_2 removal is used in the AUSM. However, the MSR and the resultant removal efficiency are model variables which may be modified as better information becomes available, or tested in sensitivity analyses. The NO_x removal efficiency for LIMB is set at a default value of 50 percent, the same value assumed for low-NO_x burners. It is also assumed that LIMB retrofits are limited to tangential and wall-fired boilers, consistent with data and assumptions regarding the retrofitting of low-NO_x burners.

The AUSM also allows LIMB to be considered at new plants subject to the RNSPS. The lower SO_2 removal efficiency requirement (currently 70 percent) is assumed to be met at a user-specified value of molar stoichiometry. NO_x emissions are assumed to be at the value of the applicable standard. Given that LIMB is still in a developmental stage, the AUSM also allows the user to specify the year in which LIMB is assumed to be commercially available. The current default is 1992.

5.2.8.3 **Capital Cost Models.** The LIMB capital cost model for the AUSM is based on four system modules: (1) reagent material handling and preparation, (2) boiler modifications, (3) particulate removal, and (4) waste disposal. Except for boiler modifications, previously described AUSM models were utilized for these components as described later.

5.2.8.3.1 **Materials Handling and Preparation**. Materials handling and preparation for LIMB is almost identical to that used in the wet limestone process. It consists of reagent (limestone) unloading, storage, and crushing operations. As with the wet FGD, the limestone is crushed to a size of 90 percent through 325 mesh (15 microns) [77]. Although earlier studies had suggested that the limestone could be pulverized with the coal, it was found that joint milling could not adequately control limestone particle size [77]. The only modification made to the previous limestone materials handling and preparation algorithm (Section 5.2.5.2.1) was to reduce it by 3.4 percent to account for the slurry feed tank which is not used since the limestone is fed dry into the boiler. The use of the limestone preparation and handling portion of the TVA model [31] to esimate LIMB costs is consistent with a LIMB feasibility study done by TVA [78]. The 3.4 percent was based on a 500 MW plant burning a 3.3 percent sulfur coal at NSPS.

Based on Equations 63 and 64, the cost for reagent capacity is:

$$DCC_{MAT} = 2.762 + 0.1278 * CAP \qquad (CAP < 18) \qquad \text{[Eq 117]}$$

$$DCC_{MAT} = 5.210 + 0.07040 * CAP \qquad (CAP \geq 18) \qquad \text{[Eq 118]}$$

where

DCC_{MAT} =Direct capital cost of limestone materials preparation and handling (10^6 - 1981$).

CAP = WSR * S.

CAP = Reagent handling system capacity (tons/hr).

S = SO_2 removal rate capacity (tons/hr).

WSR = Weight stoichiometric ratio (lb reagent required/lb SO_2 removed).

5.2.8.3.2 **Boiler Modifications**. Boiler-modification costs were defined simply in terms of a cost per kilowatt of capacity to allow them easily to be changed as new information becomes available. Boiler modification costs have been broken into two components. The first is the limestone injection mechanism. This has been estimated by TVA to be $6/KW (1983 dollars) for a 200 MW boiler [78]. The other component includes boiler modifications necessary to obtain low NO_x combustion. This can vary considerably, depending on the extent of modifications required. In a recent study where only staged combustion modifications were required on a tangential boiler, the cost was estimated at 1$/MW (1982 dollars) for a 500 KW unit [77]. The same study established the cost on a new unit to be between 0.1 to 5.5 $/KW depending on coal type and system design. In another study where new burners were estimated for retrofit on a 200 MW wall-fired boiler, a cost of $16/KW (1983 dollars) was given by Babcock and Wilcox as an order of magnitude estimate [78]. Due to wide cost variation, the boiler modification cost is modeled in the AUSM in $/KW of installed capacity and made a scenario variable so that it may be externally specified. The default value is $10/KW (1980 dollars). This assumes $5/KW for limestone injection (TVA's $6/KW deflated to 1980$) plus $5/KW for boiler modifications.

The module cost is sized in the same manner as NO_x controls, i.e., linear scaling above 250 MW and scaling by the 0.5 rule below. This gives the functional form used in the AUSM:

$$TCC_{BM} = MOD_{cost} * 15811 * (MW)^{0.5} \qquad (MW < 250) \qquad [\text{Eq } 119]$$

$$TCC_{BM} = MOD_{cost} * 1000 * MW \qquad (MW \geq 250) \qquad [\text{Eq } 120]$$

where

TCC_{BM} = Total capital cost of boiler modifications (1980$/KW)

MOD_{cost} = Base boiler modification cost for MW $\geq$ 250 (1980$/KW)

MW_g = Gross plant capacity (MW)

In addition to the uncertainty that exists in boiler modification costs, there is the uncertainty about boiler slagging and fouling and the ability to retrofit low-NO_x burners. Laboratory ash fusion tests on five regional coals showed increased slagging and fouling potential for eastern and Utah bituminous coals, decreased effects on a Wyoming sub-bituminous and midwestern bituminous, and little change with a Texas lignite [77]. The bench scale tests demonstrated that LIMB-related slagging and fouling potential will depend both on the specific coal used and on boiler design and operating parameters. EPRI has estimated that coal-fired units accounting for about 60 percent of total coal-fired utility NO_x emissions could be retrofitted with combustion modification NO_x controls [54]. In the case of pre-NSPS coal-fired boilers, it was estimated that only 38 percent of the capacity could be retrofitted with commercially available low-NO_x burners [54]. Studies aimed at better assessing the ability to retrofit NO_x controls are currently being sponsored by EPRI. These will have implications for the retrofitting of LIMB as well. Currently, the AUSM does not exclude LIMB from being considered on the basis of any site-specific factors if it is assumed to be available commercially.

5.2.8.3.3 **Particulate Control**. The existing AUSM models for particulate control and solid waste disposal are utilized with LIMB. A fabric filter (Section 5.2.5) is used as the default option for particulate control since the effects of LIMB on ESP performance are highly uncertain, but likely to cause a significant decrease in efficiency (e.g., from the 90 to 95 percent range to 70 to 80 percent [77]) due to the higher dust loadings and lower flue gas sulfur content. However, a user-specified cost of an ESP upgrade is also an AUSM option.

5.2.8.3.4 **Solid Waste Disposal**. The landfill model developed for the dry lime FGD (Section 5.2.7.4.3) is also utilized for LIMB. The calculation of total solid waste remains the same as for the dry FGD model (Equation 110) since the excess reagent exists as lime instead of limestone. This is due to the complete calcination of limestone in the boiler.

5.2.8.4 **Variable Cost Model, Excluding Utilities**. Variable costs for the LIMB system consist of reagent costs, reagent preparation costs, particulate removal and waste disposal variable costs. There are no variable costs associated with the operation of the low-NO_x burners. The variable cost models for particulate control and waste disposal are unchanged (Sections 5.2.5.4 and 5.2.6.5). Annual reagent cost is based on reagent usage:

$$ARC = CAP * 8760 * RC * CF \qquad \text{[Eq 121]}$$

where

ARC = Annual reagent cost (\$/yr)

CAP = Reagent capacity (tons/hour)

RC = Reagent cost (\$/ton)

CF = Annual plant capacity factor

The materials handling and preparation variable cost, which is included as part of the scrubber variable cost, for the wet and dry FGD systems is estimated now as a function of the materials handling direct capital cost:

$$VRR_{MAT} = 0.080 * DCC_{MAT} * CF \qquad \text{[Eq 122]}$$

where

VRR_{MAT} = Variable revenue requirement for material preparation and handling

DCC_{MAT} = Direct capital cost of material preparation and handling (Eq. 117-118)

CF = Annual plant capacity factor

This coefficient (of 8 percent) reflects recommended maintenance costs for general solids handling processes of 5 percent of direct capital costs and 3 percent for overhead [31].

5.2.8.5 **Energy Requirement and Cost Model.** Energy is used in the LIMB process for limestone crushing and handling, and for limestone calcination in the boiler. Stack gas reheating is not required since the flue gas is not cooled as in the wet FGD processes.

Electrical energy for limestone crushing and handling was estimated from the TVA model (3.4 percent sulfur, 500 MW case) by summing the power requirements and dividing by reagent usage to obtain:

$$P_{mat} = 48.9 * CAP \qquad \text{[Eq 123]}$$

where

P_{mat} = Power for limestone crushing and handling (KW)

CAP = Reagent capacity (tons/hr)

The energy required for calcination is 600 Btu/lb of limestone. This loss of energy in the boiler results in a power penalty of:

$$P_{cal} = 1,200,000 * \frac{CAP}{HR} \qquad \text{[Eq 124]}$$

where

P_{cal} = Power penalty for calcination (KW)

CAP = Reagent capacity (tons/hr)

HR = Plant heat rate (Btu/KWh)

These capacity penalties may be expressed either as a fraction of plant capacity:

$$X_{LIMB} = (EP_{mat} + EP_{cal})/KW_{plant\ capacity} \qquad \text{[Eq 125]}$$

or on an equivalent annual electricity consumption basis:

$$AEC_{LIMB} = (P_{mat} + P_{cal}) * 8760 * CF \qquad \text{[Eq 126]}$$

where

AEC_{LIMB} = Annual electricity consumption (KWh)

CF = Plant capacity factor (fraction)

5.2.8.6 **Model Performance.** Examples of the capital and variable costs predicted by the LIMB model are shown in Figures 5-19 and 5-20, respectively, as a function of coal sulfur content for reagent stoichiometries of 2, 3, and 4.. The costs are for SO_2 and NO_x removals of 50 percent and include lime handling and preparation, boiler modification, TSP removal, and solid waste disposal for a 500 MW plant. Base plant physical and economic characteristics are the same as in the sample calculation in Section 5.4. The delivered cost of lime was taken to be $65/ton.

Figure 5-19

ILLUSTRATIVE RESULTS FOR AUSM LIMB CAPITAL COST MODEL: TOTAL COST OF PARTICULATE, SO_2 AND SOLID WASTE CONTROL

(500 MW unit)

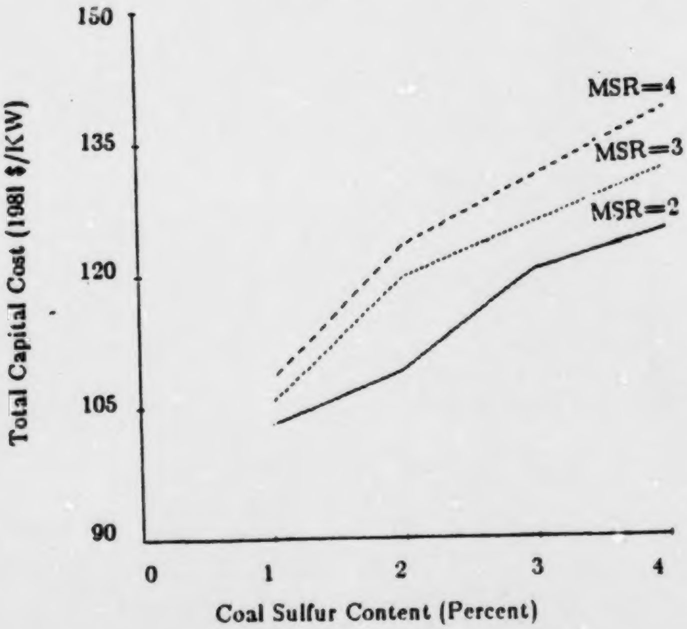
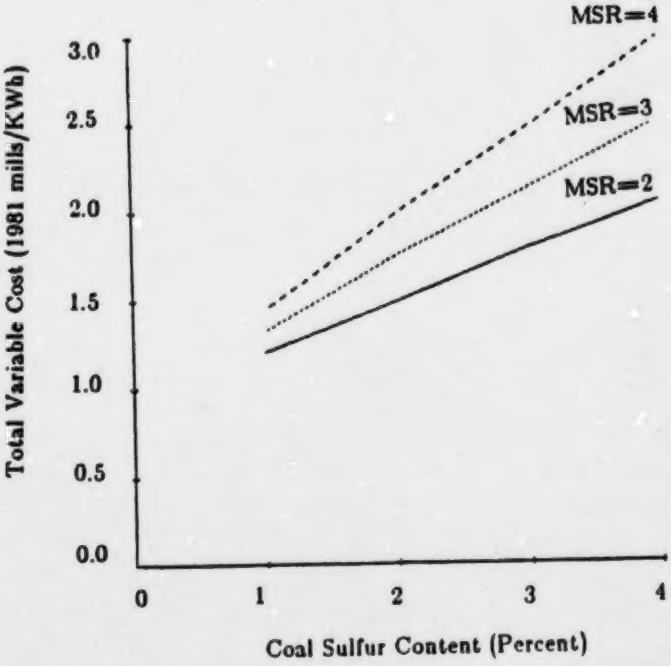


Figure 5-20

ILLUSTRATIVE RESULTS FOR AUSM LIMB VARIABLE COST MODEL: TOTAL COST OF PARTICULATE, SO_2 AND SOLID WASTE CONTROL

(500 MW; CF=0.65)



5.2.9 Economic Appraisal of Alternative Pollution Control Strategies

5.2.9.1 Introduction. One function of the AUSM pollution control module is to determine which of several alternative strategies will result in the lowest busbar cost of electricity over the lifetime of a coal-fired power plant, given a set of standards for the emission of various pollutants. For a new plant, this involves choosing between a set of alternative coals and pollution control devices. Existing plants facing tighter standards must choose among the following strategies: (1) switching coals, (2) blending the current coal with one of the alternative coals, (3) constructing pollution control equipment (with or without a change in fuel), and (4) premature retirement of the plant.

To reach a conclusion about the cheapest strategy, this section discusses how the costs of the various alternatives are assessed. Since premature retirement falls into a different category from the others, it will be discussed later. The relevant costs of the other alternatives can be broken into the following elements: (1) variable costs of pollution control equipment, (2) fuel costs, (3) capital costs of pollution control equipment, and (4) the capacity penalty associated with pollution control equipment. Note that certain costs, such as operating and maintenance (O&M) costs not associated with pollution control and the return on capital already invested at a plant, are the same for every alternative, and thus can be excluded from consideration.

Before considering each element in turn, some points are worth noting. All decisions about fuel choice and pollution control equipment are taken several years before compliance with emission standards or the start-up of a new plant are due. The lead times in the AUSM are approximately eight years for new plants and three years for retrofits (the assumed lead time for FGD systems). The costs generated in the pollution control module refer to the year in which the decision is taken; they are in 1980 dollars. The base year for costing alternatives is the first year when changes at a plant will take effect. All control technology costs generated by the pollution control module (see Sections 5.2.1 through 5.2.8) are escalated using appropriate real escalation rates before the financial analysis is begun. Many mathematical symbols are used in the analysis; these are described in alphabetical order in Table 5-22. Several mathematical identities are used without proof in the main text. The derivations of these are available in a separate report [47].

Table 5-22
SYMBOLS USED IN SECTION 5.2.9

Symbol	Meaning
a	Ad valorem rate
A_n	Ad valorem charges in year n
ADCC	Accumulated direct capital costs
AFUDC	Accumulated funds used during construction
b	Rate of return on bonds
B_n	Return on bonds in year n
c_p	Cost of alternative electric power (mills/KWh)
C	Construction time for plant
CF	Plant capacity factor
CP_L	Annual levelized cost of capacity penalty
C_T	Total annual levelized cost
CAPPEN	Capacity penalty (MW)
CWIP	Construction work in progress
d	Effective after-tax rate of return (discount rate)
D_n	Book depreciation in year n
D_n^T	Tax depreciation in year n
D_T	Present worth of tax depreciation
e	Real escalation rate/rate of return on equity
e_n	Real escalation rate in period n
E_n	Return to equity in year n
f_n	Fraction of capital expenditure incurred in year n of the construction schedule
f	Debt financing ratio/federal tax rate
F_n	Fuel cost in year n
F_L	Annual levelized fuel cost
GEN	Plant capacity (MW)
i	Inflation rate
ITC	Investment tax credit
ITC_a	Annual "amortization" of investment tax credit
itcelg	Eligibility for investment tax credit
itcrat	Investment tax credit rate

Table 5-22 (contd.)

Symbol	Meaning
K	Capital cost
K_n	Capital expenditure in year n
L	Project life
LVL(e, d, L)	Levelization factor
n	Year index
OM_L	Annual levelized O&M cost
PV(d, L)	Present value factor
PW	Present worth
r	Real discount rate
R_n	Revenue requirement in year n
R_L	Annual levelized revenue requirement
RB_n	Rate base at beginning of year n
ΔRB_n	Rate base reduction in year n
s	State tax rate
t	Composite tax rate
T	Tax life
T_n	Taxes paid in year n
T^*_n	"Deferred" taxes in year n
U	Annual fuel usage
V	Variable cost
V_1	Variable costs in first year of project
V_L	Annual levelized variable costs
w_n	Weight given to a fuel cost incurred in year n
Y_n	Years in which fuel costs are known

Section 5.2.9.2 derives some basic quantities related to tax rates and discount rates. The following sections then consider each cost element in turn.

5.2.9.2 **Tax and Discount Rates.** The financial appraisals rely on present value arithmetic; an appropriate discounting rate must be chosen. The one used is the effective after-tax cost of capital, which takes account of the proportion of debt/equity financing used by a typical utility, and also recognizes that payments of interest on bonds are tax deductible. This is the truest representation of the "cost of capital" to a utility. In nominal terms, the discount rate is given by

$$d = (1 - f)\, e + f(1 - t)\, b. \qquad \text{[Eq 127]}$$

Except for calculating the capital charge factor, the real discount rate will be used. It is derived from the nominal rate as follows:

$$r = \frac{d - i}{1 + i}. \qquad \text{[Eq 128]}$$

Note also that the tax rate in Equation 127 is a composite of federal and state taxes, derived as follows:

$$t = s + f(1 - s), \qquad \text{[Eq 129]}$$

since state taxes are deductible from taxable income for federal tax purposes.

5.2.9.3 **Variable Costs.** The information available is the annual variable cost V of operating pollution control equipment (estimated C years prior to start-up), the real escalation e of the cost, and the lifetime L of the project. The beginning-of-year variable cost in the first year of operation will be

$$V_1 = V * (1 + e)^C \qquad \text{[Eq 130]}$$

The present worth of the variable costs over the life of the project measured in the first year of operation is

$$PW = V_1 * PV(\frac{r - e}{1 + e}, L). \qquad \text{[Eq 131]}$$

where PV is the present worth formula for a constant stream of beginning-of-year costs of value unity with the discount rate r over a period L:

$$PV(r, L) = \frac{1+r}{r}\left(1 - \frac{1}{(1+r)^L}\right).$$ [Eq 132]

The argument $\frac{r-e}{1+e}$ in Equation 131 results because instead of remaining constant, the variable costs are growing at a constant annual rate e.

The present worth of the costs may be converted to an annual levelized cost using the present value function again:

$$V_L = \frac{PW}{PV(r,L)} .$$ [Eq 133]

Equations 130, 131, and 133 may be combined to give:

$$V_L = V * (1 + e)^C * PV(\frac{r-e}{1+e}, L)/PV(r,L).$$ [Eq 134]

The quotient of the two present value functions is the standard levelization formula:

$$LVL(e, r, L) = PV(\frac{r-e}{1+e}, L)/PV(r,L),$$ [Eq 135]

giving

$$V_L = V * (1 + e)^C * LVL(e, r, L) .$$ [Eq 136]

5.2.9.4 **Fuel Costs**. For this cost element, a set of fuel costs F_n pertains in years Y_n. We wish to obtain the levelized cost of burning the fuel from a start-up year Y_S to a retirement year Y_R. (Note that Y_R is the year after the last year of operation.) Assume that Y_1 is the last year for which we have a fuel cost prior to Y_S and that Y_{N+1} is the first year for which we have a fuel cost subsequent to year Y_R. Assume also that for each n, the evolution of fuel prices in the period $[Y_n, Y_{n+1}]$ is exponential.[11] Thus, the fuel escalation rate during period n is:

$$e_n = \left(\frac{F_{n+1}}{F_n}\right)^{\frac{1}{Y_{n+1} - Y_n}} - 1 .$$ [Eq 137]

The fuel price in the starting year Y_S is given by

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[11] The problem is formulated in this way since the AUSM coal supply module provides real delivered coal prices only for certain years (typically 1980, 1985, 1990, 2000, 2010, 2020, and 2040). The pollution control module interpolates by assuming a constant annual growth rate for each interval.

$$F_s = F_1(1 + e_1)^{Y_s - Y_1} \qquad \text{[Eq 138]}$$

and in the retirement year Y_R by

$$F_R = F_N(1 + e_N)^{Y_R - Y_N} . \qquad \text{[Eq 139]}$$

It can then be shown that the present worth of the cost of burning one unit of fuel over the period $[Y_S, Y_R - 1]$ measured in the year Y_s is given by

$$PW = w_s F_s + \sum_{n=2}^{N} w_n F_n + w_R F_R \qquad \text{[Eq 140]}$$

where w_s, w_n, and w_R are weighting factors for the fuel prices given by

$$w_s = \frac{1 + r}{r - e_1} \qquad \text{[Eq 141]}$$

$$w_n = \frac{e_n - e_{n-1}}{(r - e_n)(r - e_{n-1})(1+r)^{Y_n - Y_s - 1}} \qquad \text{[Eq 142]}$$

$$w_r = \frac{1}{(r - e_n)(1+r)^{Y_R - Y_s - 1}} . \qquad \text{[Eq 143]}$$

The levelized annual cost of burning the fuel is then given by

$$F_L = U * \frac{PW}{PV(r,L)} \qquad \text{[Eq 144]}$$

where U is the annual usage of the fuel.

5.2.9.5 **Capital Costs.** The revenue requirement method is the underlying basis for the derivation of the fixed charge factor used to convert a capital cost into an annualized cost over the lifetime of a project. The revenue requirement method is generally accepted as the appropriate method for evaluating alternatives in a regulated industry. Note that much of the analysis is performed in nominal dollars to account for the effect of inflation on extended construction schedules and depreciation. However, the fixed charge factor is calculated to give an annualized cost based in 1980 dollars in the first year that equipment comes on-line.

First, consider plant that is estimated to cost K 1980 dollars in year 1. The construction time is C and the first year of operation is $C + 1$. If the construction schedule is f_n (where $\sum_{n=1}^{C} f_n = 1$), the actual expenditure in year n is given by

$$K_n = K f_n (1 + i)^{n-1} (1 + e)^{n-1} , \qquad \text{[Eq 145]}$$

allowing for general inflation and the real escalation of capital cost. Assuming that capital costs are expended in the middle of each year, the capital expended in year n accrues interest for $(C + 0.5 - n)$ years before the plant comes on-line. Assuming that the effective after-tax rate of return is the appropriate interest rate to take, the total construction work in progress ($CWIP$) added to the rate base in the first year of operation, equal to the capital costs plus the accumulated funds used during construction (AFUDC), is given by

$$CWIP = K \sum_{n=1}^{C} f_n (1 + i)^{n-1} (1+e)^{n-1} (1 + d)^{C+0.5-n} . \qquad \text{[Eq 146]}$$

However, this sum is not in 1980 dollars because of the effect of inflation. To bring it back to 1980 dollars, it must be deflated over C - 0.5 years.

$$CWIP = \frac{K}{(1+i)^{C-0.5}} \sum_{n=1}^{C} (1 + i)^{n-1} (1+e)^{n-1} (1 + d)^{C+0.5-n}, \qquad \text{[Eq 147]}$$

which after rearrangement becomes

$$CWIP = K(1 + e)^{C-0.5} \sum_{n=1}^{C} f_n \left(\frac{1 + d}{(1 + i)(1 + e)}\right)^{C+0.5-n} \qquad \text{[Eq 148]}$$

Similarly, the total accumulated capital cost without allowing for interest is

$$ADCC = K(1 + e)^{C-0.5} \sum_{n=1}^{C} f_n \left(\frac{1}{(1+i)(1 + e)}\right)^{C+0.5-n} . \qquad \text{[Eq 149]}$$

If an investment tax credit is available for the project, the investment tax credit accumulated by the start-up date is

$$ITC = ADCC * itcrat * itcelg \qquad \text{[Eq 150]}$$

where *itcrat* and *itcelg* are the investment tax credit rate and investment tax credit eligibility, respectively.

The revenue requirement (in *nominal* terms) associated with a capital investment in a year n is given by

$$R_n = E_n + B_n + D_n + T_n^D + T_n + A_n - ITC - ITC_a \qquad \text{[Eq 151]}$$

where ITC is the investment tax credit (which appears in year 1 only if the credit is flowed through to investors) and ITC_a is the amortization of the investment tax credit (which applies if the credit is not flowed through). These last two terms depend on the availability and treatment of an investment tax credit. The present worth of the revenue requirement in the first year of the project is then given by

$$PW = \sum_{n=1}^{L} \frac{R_n}{(1+d)^{n-1}}. \qquad \text{[Eq 152]}$$

Then the annual levelized revenue requirement for capital related charges in *real* terms is

$$R_L = \frac{PW}{PV(r,L)} = \frac{1}{PV(r,L)} \sum_{n=1}^{L} \frac{R_n}{(1+d)^{n-1}} \qquad \text{[Eq 153]}$$

It can be shown that the present worth of the revenue requirements simplifies to

$$R_L = \frac{(1+d)CWIP - ITC - tD_T}{(1-t)\, PV(r,L)} + \frac{a * ADCC}{LVL(i,d,L)} \qquad \text{[Eq 154]}$$

where D_T is the present value of the depreciation schedule used for tax purposes, and the final term represents the present worth of the ad valorem charges (property tax, insurance, etc.) that are constant in *nominal* terms. The tax depreciation schedule is given by the following equation:

$$D_T = (ADCC - ITC) * \sum_{n=1}^{T} \frac{D_n^T}{(1+d)^{n-1}} \qquad \text{[Eq 155]}$$

where D_n^T is the fractional tax depreciation allowed in the year n where

$$\sum_{n=1}^{T} D_n^T = 1\,. \qquad \text{[Eq 156]}$$

For retrofit pollution control equipment, the most recent (1981) tax code allows five-year straight-line depreciation. That is:

$$D_n^T = 0.2 \quad \text{for} \quad n = 1, 5 \, . \qquad \text{[Eq 157]}$$

New plants have a 15-year depreciation schedule, as follows:

$$\begin{aligned} D_n^T &= 0.05 \\ D_2^T &= 0.10 \\ D_3^T &= 0.09 \\ D_4^T &= 0.08 \\ D_5^T, D_6^T &= 0.07 \\ D_7^T - D_{15}^T &= 0.06 \end{aligned}$$

5.2.9.6 **Capacity Penalty**. Most items of pollution control equipment incur a capacity penalty at plants by using some power that could otherwise be dispatched to the consumer. The penalty may also arise indirectly if the equipment uses steam that is then not available to generate power. The true cost of this penalty to the operating utility depends greatly on the circumstances in which the utility finds itself; these costs can be calculated accurately only by sophisticated techniques. If the utility has more generating capacity than it currently needs, it can replace the lost generation by dispatching the relevant plant and/or similar plants at higher capacity factors, incurring only extra variable costs. The annual levelized revenue requirement to cover the capacity penalty is then given by

$$CP_L = (F_L + OM_L + V_L) * \frac{CAPPEN}{GEN\text{–}CAPPEN} \qquad \text{[Eq 158]}$$

where F_L, OM_L, and V_L are the levelized costs of fuel, nonpollution control-related O&M expenses, and annual pollution control expenses, respectively.

However, if the utility has barely enough capacity to meet demand (i.e., if its reserve margin is close to the minimum required), the capacity must be replaced by the cheapest alternative source of power. One way to replace it is by purchasing power from outside. Another is to bring forward the construction of a new plant that would be the most economical source of power for the plant under consideration. Either way, we can think of a replacement cost for the power which is "lost" due to the capacity penalty. This cost will reflect both the variable costs and the fixed (capital) costs of generating electricity. Therefore, it will be higher than the cost calculated by Equation 158, which assumed that the utility has excess capacity. If the current cost of the alternative power is c_p, the annual levelized revenue requirement associated with the capacity penalty is:[12]

$$CP_L = CAPPEN * 8766 * CF * LVL(e,r,L) * c_p \quad \text{[Eq 159]}$$

where CF is the expected capacity factor of the plant and e is the expected real escalation rate of the alternative power cost.

In practice, the true cost of the capacity penalty will lie between the values given by Equations 158 and 159. However, since the AUSM capacity planning module aims at a desired reserve margin, it would seem most consistent to take the second approach in evaluating alternative pollution control options since increasing capacity penalties will accelerate the construction of new plants. The cost of alternative power should therefore be derived either from the planning module itself or from the assumptions used in making planning decisions. Currently, the AUSM employs a user-specified cost of purchased electricity and real annual escalation rate (default values of 55 mills/KWh and zero percent per year, respectively).

5.2.9.7 **Choosing a Pollution Control Strategy**. The total cost of a pollution control strategy is the sum of the annual levelized revenue requirements associated with each cost element:

$$C_T = F_L + V_L + R_L + CP_L \,. \quad \text{[Eq 160]}$$

The "best" strategy is the one with the lowest value of C_T.

5.2.9.8 **Early Retirement**. The AUSM currently does not consider early plant retirement as an explicit pollution control option. However, if a plant is due to be retired shortly after a compliance date purchasing low-sulfur coals or spreading the capital costs of pollution control equipment over a small number of years may be more expensive than retiring the plant to bring it into compliance. Retiring a plant will be economical if the cost of obtaining replacement power is less than the sum of the remaining "unsunk" costs at the power plant, spread over the remaining electricity that will be generated. The annualized "unsunk" costs are simply the levelized cost of the pollution control strategy plus the O&M costs. Therefore, the condition for early retirement, were this to be considered, is that

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[12] Throughout this section, a year is assumed to have 365.25 days to more correctly include the effect of leap years in levelized cost calculations. Thus, a value of 8766 hours per year is used, rather than the conventional value of 8760 used elsewhere in this report for an arbitrary year.

$$c_p < \frac{C_T + OM_L}{GEN * CF * 8766} \qquad \text{[Eq 161]}$$

where c_p is the cost of alternative power discussed in Section 5.2.4.5.

While the AUSM dispatch module may produce *de facto* early retirements by not dispatching plants with very high operating costs, the user is cautioned that scenarios that mandate the use of pollution control equipment may result in unrealistically high capital costs unless care is taken to exempt those plants that might otherwise choose early retirement as the most cost-effective strategy.

5.2.9.9 **Numerical Example.**[13] Assume that construction begins in 1982 on a scrubber that is estimated to cost $100 million in 1980 dollars. The scrubber takes three years to build and will come on-line in 1985. The fuel cost at the plant is $50 million, the annual cost of the scrubber and waste disposal is $10 million, and the capacity penalty is 20 megawatts. The plant is new and will be retired in 2020. Other assumptions (that are AUSM scenario parameters) are:

Federal taxes = 46%
State taxes = 4%
Debt ratio = 52.6%
Return on debt = 15%
Return on equity = 17%
Capital cost real escalation = 2%
Variable cost escalation = 1%
Alternative power cost escalation = 2%
General inflation rate = 9%

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[13] The numbers here are merely illustrative and do not necessarily represent AUSM default values.

Investment tax credit rate = 11%

Investment tax credit eligibility = 90%

Tax depreciation schedule = as at the end of Section 5.2.9.5

Ad valorem charges = 4.5% of invested capital

Current alternative power cost = 50 mills/KWh

The composite tax rate comes from Equation 129:

$$t = 4\% + 46\% * (1 - 0.04) = 48.16\% . \qquad [\text{Eq } 162]$$

The nominal effective after-tax discount rate is:

$$d = (1 - 0.526) * 17\% + 0.526 * (1 - 0.4816) * 15\% = 12.15\% \qquad [\text{Eq } 163]$$

and the "real" discount rate is:

$$r = \frac{12.15\% - 9\%}{1 + 0.09} = 2.89\%. \qquad [\text{Eq } 164]$$

5.2.9.9.1 **Variable Costs.** The variable costs are given by the following equation:

$$\begin{aligned} V_L &= \$10\ m * (1.01)^3 * LVL(1\%, 2.89\%, 35 \text{ yrs}) \\ &= \$10\ m * 1.030 * 1.157 \\ &= \$11.92m. \qquad [\text{Eq } 165] \end{aligned}$$

5.2.9.9.2 **Fuel Costs.** Suppose we have estimated fuel costs of $50 million for 1985, $75 million for 2005, and $90 million for 2025. The estimated fuel cost in the retirement year 2020 is then $85.99 million. The escalation rates for the periods 1985-2005 and 2005-2020 are 2.05 percent and 0.92 percent. Therefore, from Equations 141, 142, and 143, the weights for the costs in the years 1985, 2005, and 2020 are 122.45, -39.77, and -19.26, respectively. Those are used to determine the present value of the fuel costs as follows:

$$\begin{aligned} PW &= (w_{1985} * \$50m) + (w_{2005} * \$75m) + (w_{2020} * \$85.99m) \\ &= (122.45 * \$50m) + (-39.77 * \$75m) + (-19.26 * \$85.99m) \end{aligned}$$

$$= \$1{,}483.93m$$

$$F_L = \$1{,}483.93m/PV(2.89\%, 35)$$

$$= \$66.03m. \qquad \text{[Eq 166]}$$

5.2.9.9.3 **Capital Costs**. Using Equations 148, 149, and 150, the cost variables accumulated during construction come to:

CWIP = $107.98 million
ADCC = $81.20 million
ITC = $8.04 million

From Equation 154, the annual revenue requirement then becomes:

$$R_L = \frac{\$1.1215 * 107.98 - 8.04 - 0.4816D_T}{(1 - 0.4816) * PV(2.89\%, 35)} + \frac{0.045 * \$81.20}{LVL(9\%, 12.15\%, 35)} \qquad \text{[Eq 167]}$$

Taking D_T from Equation 155 gives

$$D_T = (\$81.20m - \$8.04m) * 0.80556$$

$$= \$58.93m \qquad \text{[Eq 168]}$$

and

$$R_L = \frac{\$1.1215 * 107.98 - 8.04 - 0.4816 * 58.93}{(1 - 0.4816) * 22.473} + \frac{0.045 * 81.20}{2.479}$$

$$= \$8.74m \qquad \text{[Eq 169]}$$

The low implied fixed charge factor of 8.74 percent is related directly to the high inflation rate assumed. It is well known that inflation confers advantages on investing in equipment since the present value of later capital charges is diminished.

5.2.9.9.4 **Capacity Penalty**. If the plant is expected to be run at a 65 percent capacity factor and the estimated cost of electricity is $50 per megawatt hour (50 mills/KWh), then

$$CP_L = 20 * 8766 * 0.65 * LVL(2\%, 2.89\%, 35) * 50$$

$$= \$7.69m.$$ [Eq 170]

The total annual levelized revenue requirement then becomes:

$$\begin{aligned} C_T &= \$11.92m + \$66.03m + \$8.74m + \$7.69m \\ &= \$94.38m. \end{aligned}$$ [Eq 171]

5.2.9.9.5 **Retrofit Plant Variation**. Assume that the plant is a retrofit plant due to retire in 2000. The levelization factors and present value factors must change because of the shorter lifetime. Also assumed are a five-year straight-line tax depreciation schedule and 100 percent eligibility for the investment tax credit. The levelized variable cost falls to

$$V_L = \$11.00m$$ [Eq 172]

and the present worth of the fuel costs becomes

$$\begin{aligned} PW &= (22.45 * \$50m) + (-79.89 * \$67.77m) \\ &= \$708.61 \end{aligned}$$ [Eq 173]

and

$$F_L = \$57.23m.$$ [Eq 174]

Similarly, the capacity penalty cost falls to:

$$CP_L = \$6.50m.$$ [Eq 175]

The change to the capital cost equation is more complex. The result is

$$\begin{aligned} R_L &= \frac{1.1215 * 107.98 - 8.12 - 0.4816 * 58.87}{(1 - 0.4816) * 12.383} + \frac{0.045 * 81.20}{1.634} \\ &= \$15.42m. \end{aligned}$$ [Eq 176]

The fixed charge factor is higher, in spite of the higher tax credit and faster tax depreciation schedule. In summary, however, the overall costs are lower because of the shorter lifetime:

$$\begin{aligned} C_T &= \$11.00m + \$57.23m + \$15.42m + \$6.50m \\ &= \$90.15m. \end{aligned}$$ [Eq 177]

5.2.10 Decision Criteria for Control Strategy Selection

5.2.10.1 **Introduction.** Another function of the pollution control module is to determine which of several alternative strategies will result in the lowest busbar cost of electricity over the lifetime of a coal-fired plant, given a set of standards for the emission of various pollutants. The models are used to estimate costs of building and operating pollution control equipment, and the financial models are used to levelize escalating costs and annualize capital costs. This section describes the range of alternative pollution control strategies available to plants.

Pollution control strategies must be selected both for new plants and for existing plants subject to changes in emission standards. Since the form of regulations applicable to new and existing plants differs, each circumstance is considered separately.

The pollution control module deals with nitrogen oxides (NO_x), sulfur dioxide (SO_2), and total suspended particulates (TSP). Broadly, NO_x and TSP are dealt with by installing control equipment. For existing plants, SO_2 emissions may be brought into compliance with standards by switching coals, blending coals, and by building control equipment with or without also switching coals. Note also that for existing plants compliance with SO_2 and TSP standards may be required in different years. Therefore, three different compliance permutations must be considered: only TSP compliance, only SO_2 compliance, and simultaneous compliance with both standards. New NO_x standards for existing plants usually are considered together with new SO_2 standards, but they also may be treated separately. New and existing plants are now considered in turn.

5.2.10.2 **New Coal-Fired Plants.** New coal-fired power plants beginning construction after 1978 are subject to the Revised New Source Performance Standards (RNSPS). For TSP, a ceiling of 0.03 pounds per million Btu of coal burned is specified. For NO_x the standard is 0.6 pounds per million Btu (bituminous coal). For SO_2 a more complex two-tier standard applies:

1. Ninety percent of the sulfur in the original fuel must be removed, but no emissions may exceed 1.2 pounds per million Btu measured over a 30-day averaging time.

2. If emissions are less than 0.6 pounds per million Btu over a 30-day averaging time, only a 70 percent removal of sulfur is required.

For an individual coal, this regulation implies a unique level of required sulfur removal. Table 5-23 shows the removals required and the resultant emissions for four ranges of coal sulfur content. In the AUSM it is possible to alter the upper and lower sulfur removals and emission caps associated with the RNSPS, and the boundaries between the four classes of coal given in Table 5-23 are recomputed automatically.

For a new plant, the pollution control module must do two things. First, it must select a coal for the plant from among the 33 delivered coals available (three ranks each with 11 sulfur categories). It must then choose and calculate costs of appropriate pollution control equipment. The structure of these decisions is relatively simple. Each of the possible coals is examined in turn. The sulfur content and higher heating value of the coal are used to determine the level of sulfur removal required by the RNSPS; then the costs and capacity penalty associated with all flue gas scrubbing options are calculated. When a wet FGD system is considered, the costs of controlling particulate emissions to meet the RNSPS are calculated for each of the three types of equipment (a cold-side electrostatic precipitator, a hot-side

Table 5-23
REQUIRED SULFUR REMOVAL EFFICIENCIES FOR PLANTS SUBJECT TO RNSPS

Coal Sulfur Content	Required Removal Efficiency	SO_2 Emissions
>12 lbs/MBtu	>90%	1.2 lbs/MBtu
6-12 lbs/MBtu	90%	0.6-1.2 lbs/MBtu
2-6 lbs/MBtu	70%-90%	0.6 lbs/MBtu
<2 lbs/MBtu	70%	<0.6 lbs/MBtu

precipitator, and a fabric filter). For a dry FGD system, only a fabric filter is considered. The levelized annual revenue requirement associated with each particulate control option is calculated (the derivation of the quantity is discussed in Section 5.2.9), and the cheapest device is chosen. The revenue requirement associated with solid waste disposal is then calculated. NO_x controls are assumed to meet RNSPS requirements for new boilers, which depend only on coal rank. For each coal, the sum of the levelized annual revenue requirements for coal, flue gas desulfurization equipment, TSP control equipment, NO_x control, and solid waste disposal are calculated, and the system that has the lowest overall cost (including the cost of pollution control) is selected. Consistent with current industry criteria, a lifetime capacity factor of 65 percent is used for the variable cost algorithms.

5.2.10.3 **Existing Coal-Fired Plants**. Coal-fired units beginning construction after 1971 but before 1978 are subject to federal New Source Performance Standards (NSPS), which specify a 1.2 pounds per million limit on SO_2 emissions, 0.7 pounds per million Btu for NO_x, and a 0.1 pounds per million Btu limit on TSP. While most NSPS units are already operating at the beginning of the AUSM simulation period, those coming on line after 1980 are treated similarly to new RNSPS plants described earlier, and standards and available options are adjusted appropriately.[14] The model also recognizes that these emission limits might be reduced in the future, or be overridden by more stringent state standards.

Plants predating the 1971 NSPS have SO_2 and TSP limits set as part of State Implementation Plans (SIPs) submitted to and approved by the Environmental Protection Agency. These limits are unit-specific and are recorded in the AUSM unit inventory file. In general, there are no NO_x standards for coal-fired SIP units. However, certain plants have not yet attained compliance with their SIP standards for TSP and/or SO_2. In its present version the AUSM can be run to, (1) force plants to come into SIP compliance (for TSP and/or SO_2), (2) reduce all SIP standards to a specified level (e.g., two pounds of sulfur dioxide per million Btu), and (3) reduce all SIP standards by a fixed percentage. In addition, individual site-specific standards can be set through modification of the unit inventory.

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[14] For example, the user may specify the year before which options such as dry FGD and LIMB are assumed to be unavailable.

The three permutations of TSP and SO_2 compliance are now considered separately. In all cases the lifetime capacity factors assumed for various remaining plant lives are shown in Table 5-24. These figures are based on historical data, but can be altered by the AUSM user if desired. The cost of building equipment at existing plants is assumed to be greater than at new plants because of the extra problems typically involved with retrofits. Accordingly, a "retrofit factor" is applied to all capital cost estimates at existing plants. The current default value is 1.3 (i.e., a 30 percent cost increase over that for an equivalent new plant), consistent with current industry estimates.

5.2.10.3.1 **TSP Compliance.** This is the simplest case. The actual removal of TSP at each plant is compared with that which would be required to meet the TSP standard. Complying (or overcomplying) plants are left as they are, while out-of-compliance plants are assumed to upgrade their existing TSP device or to build a new one to just attain the required emission level. The levelized revenue requirement associated with building and operating each type of TSP device (cold precipitator, hot precipitator, fabric filter, and combined precipitator/mechanical collector, which is costed as a cold precipitator) is calculated, and the device with the lowest cost is chosen.

Table 5-24
LIFETIME CAPACITY FACTORS ASSUMED FOR EXISTING PLANTS[a]

Remaining Plant Life from the Compliance Year	Default Value of Remaining Lifetime Capacity Factor
>20 years	60%
11-20 years	50%
<10 years	35%

[a] *Historical values based on Federal Energy Regulatory Commission Data [TVA] are 0.51, 0.43, and 0.34. These numbers were increased to account for higher plant utilization expected in the future, especially in conjunction with FGD system retrofits.*

Note that devices other than the one currently used at the plant are costed as though they are being built from scratch, while the current type of device (usually a cold-side ESP) is upgraded. This produces a strong bias for the current device, which is almost always chosen.

The costing method for upgrades is slightly different from that used for new equipment. Each TSP removal device is characterized by a size parameter (the collection area for a precipitator and the cloth area for a fabric filter). For upgrading, the incremental collection area required to achieve the applicable emission limit is computed and fed into the cost algorithms presented earlier. Because of the economies of scale inherent in the cost algorithms, constructing a device and then upgrading it will be more expensive than simply building the original device to the upgraded standard. This is done to obtain a conservative estimate of upgrade costs.[15]

As an alternative method, upgrade costs for cold-side ESPs may be specified directly by the user in terms of a dollar per kilowatt capital cost plus a mills per kilowatt-hour additional operating cost (1980 basis). Separate values may be specified for three cases involving use of an ESP with (1) low sulfur coal, (2) dry FGD retrofit, and (3) LIMB retrofit. The first case nominally corresponds to conventional flue gas conditioning. The AUSM default is a $5/KW capital cost. The second two cases reflect future possibilities in conjunction with SO_2 removal, discussed later.

5.2.10.3.2 **SO_2 Compliance**. The current level of SO_2 removal at each plant (if any) is compared with that which would be required to meet the SO_2 standard. Complying (or overcomplying) plants are left as they are.

Out-of-compliance plants already equipped with scrubbers are assumed to have the FGD system upgraded using a simple capital cost model of a user-specified dollars per kilowatt. The SO_2 removal efficiency is increased accordingly (up to a maximum of 95 percent), and all subsequent variable operating costs and the capacity penalty are increased as determined by the appropriate algorithms. If this is insufficient to achieve SO_2 compliance (as at plants employing only partial scrubbing), the cost of additional FGD capacity is estimated by taking the difference in cost between the current system and final system capacity.

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[15] A detailed technical analysis of upgrade costs was not within the scope of this effort.

Out-of-compliance plants with no scrubbers face four alternatives: (1) retrofit an FGD system for use with the existing coal, (2) switch to a new coal which would result in SO_2 compliance without a scrubber, (3) blend the existing coal (or "first" coal if the plant currently burns a blend) with an alternative coal, and (4) build an FGD system and simultaneously switch to a new coal (which could be higher or lower in sulfur, but of the same coal rank).

The first stage is creation of "blend" coals, which may subsequently be treated as if they were simple alternative coals, thus effectively reducing the number of strategies to three. Blends are created by mixing the existing coal with the lowest cost coals in other sulfur categories (provided by the coal supply module), weighting all properties according to energy content. Blends capable of complying with SO_2 standards are considered with other unblended coals. A user-specified factor is applied, such that coal blending is not considered unless there is some minimum cost advantage over simple compliance coals. (The present AUSM default value is 2 percent based on coal energy content.)

The cost of building an FGD system for use with the current coal or an alternative coal (excluding blends) is based on the SO_2 removal efficiency that just achieves compliance with the SO_2 standard. Depending on the specified averaging time for the standard, a design factor accounting for the variability of sulfur in coal may be applied to "oversize" the FGD system in order to assure compliance (see Equation 69). As with TSP devices, a retrofit factor is used to increase the capital costs of scrubbers to allow for the extra costs associated with retrofitting. The total cost associated with each SO_2 removal option is the annual levelized cost of burning the particular coal, plus the annual levelized revenue requirements for building and operating the FGD system, together with applicable costs for the TSP device and solid waste disposal systems. The three types of retrofit FGD systems considered are the wet limestone, dry lime, and limestone injection (LIMB) processes described earlier in this report.

The unblended alternative coals considered at existing plants are those of the same rank as the coal currently used (i.e., it is assumed, for example, that a sub-bituminous coal cannot be used in boilers designed to burn bituminous coal). Therefore, 11 alternative coals are considered, one for each sulfur category. The number of blends considered depends on the sulfur content of the existing coal, plus the SO_2 standard.

For each alternative coal that would comply with the SO_2 limit (including blends), the annual levelized revenue requirement is calculated. Although this is nominally the SO_2 compliance case, particulate emissions also must be considered when alternative coals are involved. This is because a switch to coal with a higher ash content and/or a lower sulfur content can cause a deterioration in particulate emissions, which is assumed to be unacceptable, even in the case of SO_2 compliance only. Therefore, for each alternative coal, as well as for each SO_2 removal system, the precipitator plate collection area (or cloth area if a fabric filter is involved) required to maintain particulate emissions at their original level is calculated and compared to the actual current collection area (estimated from data reported in the AUSM unit inventory). If the current collection area is adequate, the TSP removal efficiency is adjusted to maintain the original particulate emission rate. If the current collection area is inadequate, the required TSP removal is calculated and the costs of upgrading or replacing the current device are calculated, as described for the TSP compliance case. For dry FGD and LIMB retrofits the feasibility of upgrading an existing ESP remains unknown. Hence, the AUSM default is to require a new fabric filter, though this may be overridden by a user-specified ESP upgrade cost. In either case, the costs of operating, plus possibly replacing or upgrading the current TSP device and waste disposal system are added to the annual levelized cost of the alternative coal to give a total cost for each option. The option with the lowest overall lifetime levelized revenue requirement is selected. Note that if a NO_x reduction also is required, its cost is included with LIMB, but added separately in conjunction with wet FGD, dry FGD, or coal switching.

5.2.10.3.3 **Both SO_2 and TSP Compliance**. This case is fundamentally a variation of the SO_2 compliance case. It assumes that SO_2 and TSP emissions are required to comply with standards in the same year rather than in years that are separately specified. Thus, the only difference from the case above is that, for each alternative coal/technology combination, it is required that TSP emissions be at the original level or meet the required TSP emission limit, whichever is less. The current device again is replaced or upgraded if necessary. If the current device can "overcomply," it is allowed to do so.

5.2.10.4 **Existing Oil- and Gas-Fired Plants**. While the AUSM was designed primarily to analyze emission reduction strategies for coal-fired power plants, some emission reductions also may be achieved at existing oil- and gas-fired plants. The AUSM can consider nitrogen oxide emission reductions through combustion modifications at oil- or gas-fired plants, and sulfur emission reductions through fuel switching at oil-fired plants. (Conversions from oil to coal firing are specified separately by AUSM capacity planning module and treated as coal-fired units for purposes of pollution control analysis.)

NO_x control options were discussed in Section 5.2.3.1. Applicable strategies are analyzed and take effect in the compliance year specified in the scenario.

Sulfur emission reductions at existing oil-fired plants are assumed to be achieved by switching to a lower sulfur oil. The method of specifying alternative fuel quality and cost was specified by Badger and Stukel [79], based on a study by Capone and Collins that is included as Appendix 5b. The sulfur content of residual oil is assumed to be a continuous variable. Price varies with percent sulfur (%S) (see Appendix 5b):

$$P_1 = P_2 \left(\%S_1 / \%S_2 \right)^{-0.111471} \qquad \text{[Eq 178]}$$

where P_i = Price per barrel for oil i, and

$\%S_i$ = Percent sulfur for oil i.

Fuel heating value also varies with sulfur content. The algorithm used in AUSM to estimate the heating value of alternative fuels was derived from data reported in Appendix 5b:

$$HHV = \begin{cases} 6.170 - 0.060\ (\%S) & \text{for } \%S \le 0.3 \\ 6.13177 + 0.06743\ (\%S) & \text{for } \%S > 0.3 \end{cases} \qquad \text{[Eq 179]}$$

where HHV = Oil heating value (10^6 Btu per barrel), and

%S = Percent sulfur in oil.

Required reductions in SO_2 emissions are calculated just for coal-fired plants [Eq 23] except that all fuel-bound sulfur is assumed to be converted to SO_2 (i.e., small emissions of other sulfur compounds are treated as SO_2). Since the AUSM unit inventory reports oil heating value in units of Btu per gallon, the fuel specific gravity must be estimated in order to calculate SO_2 mass emission rates in the specified units of pounds per million Btu. We again used data reported in Reference 80 to derive a relationship that is assumed to apply to existing oils as well as to new ones:

$$SG = \begin{cases} 0.91 & (\%S \leq 0.3) \\ 0.90571 + 0.01429\,(\%S) & (\%S > 0.3) \end{cases} \qquad \text{[Eq 180]}$$

where, SG = oil specific gravity (lb oil/lb H_2O). This number is multiplied by the density of water (8.328 pounds per gallon) to obtain the density of oil. The resultant SO_2 emissions are assumed to precisely comply with the standard.

5.3 Data Choices and Rationale

Section 5.2 described many of the AUSM user-specified parameters related to the pollution control module, and the default values assumed. Several additional parameters are summarized here.

Table 5-25 shows parameters related to coal-fired boilers. The rationale for specific data choices is indicated by either a reference number or another statement. Note that Table 5-25 does not include additional data read from the AUSM unit or plant inventories, as discussed in Section 5.2.

Table 5-26 summarizes several parameters used to calculate emissions from oil- and gas-fired utility boilers. These emission factors are taken from Reference 4.

5.4 Stand-Alone Module Results

This section illustrates typical numerical values stemming from use of the models described in Section 5.2. The costs of individual technologies are examined using hypothetical data inputs to characterize parameters found in the AUSM data base. A sample calculation is provided below to illustrate use of the models for calculating ESP, FGD, and solid waste disposal costs. Other illustrative results were included throughout Section 5.2 in graphical form.

Table 5-27 summarizes the model input data for a new 500 megawatt plant, on which the calculations are based. For this illustration, the fixed charge factor (normally calculated by the AUSM pollution control module) is taken to be 0.15, and the indirect cost factors are assumed to include AFUDC (which is

Table 5-25

PARTIAL LIST OF DATA CHOICES FOR COAL-FIRED POWER PLANTS

Device or System Component	Property of Characteristic	Default Value	Reference or Rationale
Coal Properties	Rank classification	Bituminous HHV[a] ≥ 10,500 Sub-bituminous 8300 ≤ HHV < 10,500 Lignite HHV < 8300	ASTM D388 (Ref.40)
	Moisture content (percent)	Bituninous - 10 Sub-bituminous - 25 Lignite - 35	Refs. 31, 37-40
Boiler Properties	Excess combustion air	35% (20% at boiler, 15% in leakage at air preheater)	Estimate of current design practice
	Fracion ash to overhead (flyash)	0.50 dry bottom 0.35 wet bottom and spreader stoker 0.10 cyclone 0.315 lignite - dry bottom 0.335 lignite - cyclone 0.34 lignite - spreader stoker	Ref. 4
	Sulfur retention in ash (fraction of total)	0.025 for bitumninous 0.125 for sub-bituminous 0.25 for lignite	Ref. 4 Ref. 15
	NO_x emission factors for uncontrolled boilers (ton NO_x/ton coal)	0.0105 dry bottom 0.017 wet bottom 0.0185 cyclone 0.0075 tangential 0.007 spreader stoker 0.006 lignite - dry bottom 0.007 lignite - wall 0.004 lignite - tangential 0.0085 lignite - cyclone 0.003 lignite - spreader stoker	Ref. 4
	Gas temperature	700°F before air preheater 300°F after air preheater	Estimate of current design practice
FGD system	Design SO_2 removal efficiency	0.90	Ref. 31
	Minimum FGD size	60 MW	Ref. 31
	Minimum FGD Bypass	60 MW	Ref. 31

Table 5-25 (continued)

PARTIAL LIST OF DATA CHOICES FOR COAL-FIRED POWER PLANTS

Device or System Component	Property of Characteristic	Default Value	Reference or Rationale
	$CaSO_3$ oxidation to $CaSO_4$	0.90	Ref. 35
	Construction times and expenditure schedule	3 years, equally divided	Estimate of current practice
	Land cost	$5000 per acre	Ref. 31
	Limestone cost	$8.50 per ton	Ref. 31
	Direct capital cost retrofit factor	1.3	Refs. 31 & 41
Particulate control	Contruction time and expenditure rate	2 years, equally divided	Estimate of current practice
	Direct capital cost retrofit factor	1.3	Refs. 31 & 41
	Bag repalcement cost	$0.75 per square foot	Ref. 17

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[a] Moist, mineral matter-free basis, defined as $HHV_{mmf} = [\ (HHV - 50 * \%S\ ) / (100 - (1.08 * \%A + 0.55 * \%S))\ ] * 100$, where HHV, %S and %A are higher heating value, percent sulfur and ash on a moist as-received basis.

Table 5-26

EMISSIONS FACTORS FOR OIL- AND GAS-FIRED UTILITY BOILERS[a]

Pollutant	Boiler Type	Emission Factor
Gas-fired boilers		
SO_2	General	$0.3 * 10^{-6} \dfrac{\text{ton of emission}}{\text{1000 SCF gas input}}$
TSP	General	$2.5 * 10^{-6}$
NO_2	General	$275 * 10^{-6}$
NO_2	Tangential	$138 * 10^{-6}$
Oil-fired boilers		
SO_2	General	$(160 * S)^{b} \dfrac{\text{lbs of emission}}{\text{1000 gal. oil input}}$
TSP[c]	General	$(10*S + 3)^{b}$
NO_2	General	105
NO_2	Tangential	42

[a] *From Reference 4.*
[b] *S = Percent sulfur in fuel.*
[c] *For number 6 residual oil.*

Table 5-27

MODEL PARAMETERS FOR SAMPLE CALCULATION

Control Options

Flyash control:	Cold-side ESP
SO_2 scrubber:	Limestone FGD with forced oxidation
Waste disposal:	Landfill

Plant Characteristics

$MWg = 500$ MW

$HR = 9500$ Btu/KWh

$CF = 0.65$

$f_e^a = 0.50$

$f_e^s = 0.975$

$e = 0.35$

$T = 760$ R

$f_{sol} = 0.80$

$O_X = 0.90$

Coal Characteristics (as fired)

$HV = 11700$ Btu/lb

$\%S = 3.50$

$\%A = 15.0$

$\%m = 4.0$

Emission Constraints

$ECa = 0.03$ lbs TSP/MBtu

$ECs = 0.60$ lbs SO2/MBtu

Economic Parameters

$UC_{elect} = \$0.055$/KWh

$RC = \$8.50$/ton

$LC = \$5000$/acre

$FCF_{pc} = 0.150$

$ICF_{esp} = 0.500$

$ICF_{fgd} = 0.800$

$ICF_{swd} = 0.750$

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also calculated separately in the AUSM). All other parameters represent data found in the AUSM unit inventory for a new plant. Since the values presented here are rounded from a computer program, rounding error may prevent exact duplication unless all calculations utilize eight significant figures.

First, the required TSP and SO_2 removal efficiencies are calculated from Equations 20 and 23, respectively:

$$\eta_{TSP} = 99.5\% \text{ and} \qquad [\text{Eq } 181]$$

$$\eta_{SO_2} = 89.7\%. \qquad \text{[Eq 182]}$$

Next, key plant flow rates are calculated:

$$G\,(Eq\ 18) = 1.63 * 10^6\ acfm \qquad \text{[Eq 183]}$$

$$A\,(Eq\ 19) = 15.2\ tons/hr \qquad \text{[Eq 184]}$$

$$S\,(Eq\ 25) = 12.4\ tons/hr \qquad \text{[Eq 185]}$$

For the cold-side ESP assumed here,

$$SCA\,(Eq\ 30) = 0.338\ ft^2/acfm. \qquad \text{[Eq 186]}$$

Thus, $(AR)_{esp} = G*(SCA) = 551{,}000\ ft^2$.

The total direct cost in 1981 dollars is then

$$DCC\,(Eq\ 42) = \$11.53\ million \qquad \text{[Eq 187]}$$

and the total capital cost is

$$TCC\,(Eq\ 1) = \$17.30\ million. \qquad \text{[Eq 188]}$$

This is equivalent to $35 per kilowatt, based on gross plant capacity.

Similarly, the TSP variable cost, excluding utilities, is

$$TVC\,(Eq\ 45) = \$0.043\ million. \qquad \text{[Eq 189]}$$

The auxiliary power requirement is calculated to be 0.326 percent of gross plant capacity, or

$$P_{esp}\,(Eq\ 47) = 1.63\ MW. \qquad \text{[Eq 190]}$$

If the marginal cost of power is taken to be 5.5 cents per kilowatt hour, the additional variable cost amounts to $0.51 million per year, bringing the total variable cost to $0.55 million. Then, from Equation 2, the annual revenue requirement becomes

$$ARR = \$3.15\ million. \qquad \text{[Eq 191]}$$

The FGD costs are calculated similarly. First, the permissible bypass is calculated assuming a maximum FGD efficiency of 90 percent SO_2 removal. The permissible bypass is

$$f_{byp}\,(Eq\ 26) = 0.33\%,\ or\ 1.6\ MW. \qquad \text{[Eq 192]}$$

Because this does not satisfy the default criterion of 60 megawatts minimum bypass, no bypass is implemented, and the scrubber operates at the required 89.7 percent removal efficiency (this example assumes no effects from sulfur variation in coal).

The reagent stoichiometric ratio (WSR) is

$$WSR\,(Eq\ 71) = 2.35\ lbs\ CaCO_3/lb\ S. \qquad \text{[Eq 193]}$$

The materials handling capacity is then

$$CAP\,(Eq\ 62) = 29.1\ tons\ CaCO_3/hr. \qquad \text{[Eq 194]}$$

Since this is greater than 18 tons per hour, the associated direct capital cost is \$7.51 million (from Equation 64).

From Equation 68, the number of operating and redundant scrubber trains is

$$NOP = 4 \quad \text{and} \quad NRD = 1. \qquad \text{[Eq 195]}$$

The total direct scrubber cost, from Equations 64 and 66 (times 1.04 for forced oxidation), is then \$38.06 million. This brings the total FGD system direct cost to

$$DCC = \$45.57\ million. \qquad \text{[Eq 196]}$$

The addition of indirect costs (Eq 1) brings the total capital cost to:

$$TCC = \$82.03\ million. \qquad \text{[Eq 197]}$$

This is equivalent to \$164 per kilowatt, based on gross plant capacity.

The variable costs of FGD operation, excluding utilities (times 1.04 for forced oxidation), are then

$$\text{VRR (Eq 76)} = \$7.39 \text{ million.} \qquad \text{[Eq 198]}$$

Utility requirements are found to be 3.95 percent of gross plant capacity, or (Equations 77 through 81):

$$P_{fgd} = 19.7 \text{ MW.} \qquad \text{[Eq 199]}$$

Again, at 5.5 cents per kilowatt hour, the annual utility cost is \$6.17 million, bringing the overall variable cost to \$13.56 million. Using Equation 2, the annual revenue requirement is then \$25.87 million. This is equivalent to approximately \$300 per ton of SO_2 removed.

Solid waste disposal costs follow in like fashion (see Table 5-13). The total capital cost is \$19.72 million (equivalent to \$39 per kilowatt), and the annual revenue requirement is \$15.5 million.

For this example, the combined cost of particulate control, SO_2 control and solid waste disposal amounts to \$238 per kilowatt in capital cost and \$34.2 million in total revenue requirement (12.0 mils per kilowatt hour), with all costs reported in 1981 dollars. In the AUSM, all costs are adjusted to 1980 dollars for consistency with other model components.

5.5 Conclusion

This chapter has described the major elements of the pollution control module of the Advanced Utility Simulation Model. Data choices have been discussed along with a presentation of results and sample calculations. Additional details concerning the model design and operation are provided in a separate program documentation [47] and in extensive source code comments.

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APPENDIX 5a. SIMULATING MARKET MANAGEMENT SYSTEMS USING THE ADVANCED UTILITY SIMULATION MODEL

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5a.1 Introduction

5a.1.1 Objectives

The Advanced Utility Simulation Model (AUSM) was designed as a tool to be used by public policy analysts to evaluate many different environmental regulatory programs. Most existing environmental regulations impose unit-specific emission standards on the American utility industry. Also, newer units are subjected to technology requirements mandating a minimum removal level of SO_2 in the flue gases. The pollution control module of AUSM is designed to simulate utility response to pollution control compliance required by a change in emission standards: choose the least-cost compliance option for a generating unit given a new standard. This logic flow is acceptable when AUSM is employed to simulate traditional environmental management approaches. Currently, policies being considered for acid-deposition mitigation and revisions to the Clean Air Act of 1978 do not explicitly set new standards for individual generating units. Several proposed regulations would have the federal government set an emissions cap, defined as a quantity of pollutant emitted over a period of time, for various states or regions of the country. A regional authority could implement such a policy in many ways, including establishing unit-specific emission standards. On the other hand, innovative management polices that directly utilize economic incentives, such as a transferable discharge permit (TDP) program, could be employed. Under a market program, the level of pollution abatement of each generating unit is determined by the marginal cost of pollution abatement.

Simulation of a TDP program is of particular interest to policy analysts because the competitive market encourages the least-cost compliance strategy for a system of dischargers to comply with a regional emissions cap. In this analysis, the market solution is also the least-cost, and therefore, the cost of a TDP program can be used as a benchmark to measure the cost efficiency of other more restrictive management programs. Cost efficiency of market management approaches has been demonstrated for many environmental systems [1,2,3,4]. Simulating a TDP market using AUSM extends past analyses in several ways. The design of AUSM permits TDPs to be evaluated in a dynamic system where production of pollution varies from year to year and where dischargers enter and leave the system on a regular basis. In addition, objectives other than cost efficiency are evaluated. Furthermore, when the AUSM market simulation is carried out in conjunction with the Multi-Period, Multi-State (MPMS) long-range planning preprocessor, changes in the value of a permit are monitored in time and many of the impacts of the market on plant production levels are captured in the decision-making processes.

5a.1.2 Analytical Approach and Rationale

A TDP program simply extends the concept of a regional emission cap to an annual cap on emissions from individual generating units or plants. Under such a program, the level of emissions for each individual discharger is determined by a competitive market; therefore, a discharger's emissions level (and the corresponding emissions standard) is not known prior to the market simulation. The major conceptual difference between compliance induced by a new emissions standard and the simulation of a TDP market is that the compliance module is employed to generate an estimate of each discharger's cost curve rather than simply the best compliance option to meet a new standard. The cost curves are utilized by market routines in determining the level of pollution abatement for each generating unit based on the marginal cost of a discharger's compliance options.

Two approaches are available in employing AUSM to simulate the institution of a market system to meet compliance with a regional SO_2 emissions cap. The first approach, called the SORT method, simulates a least-cost compliance for a statewide permit market using the state-level AUSM as the only modeling tool. The pollution control module assumes the market region to be defined as a state, although regions as small as a multiplant bubble of all a utility's power plants or a single power plant with multiple units can be easily handled with further development.

The second approach, called the FUTURS method, utilizes data provided by the MPMS preprocessor to simulate a dynamic market for emissions rights. Dual variables and capacity factors from the MPMS linear programming model are passed to the national-level AUSM which then simulates the SO_2 permit market on a unit or plant level. When using data provided by the MPMS preprocessor with the FUTURS method, AUSM can simulate a permit market for a region as large as a multistate power pool. The two methods of simulating a TDP market involve different assumptions and different levels of computational complexity that are discussed later.

5a.2. Analytical Structure

5a.2.1 Overview of Assumptions

The two methods of simulating a market system for SO_2 permits utilize similar concepts. Both techniques use a marginal cost analysis in determining the optimal level of pollution abatement for each discharger. The five assumptions common to both methods include:

1. All market participants utilize the same assumptions about future uncertainties (power demand projections, timing and technology of capacity additions) in developing a long term compliance plan.

2. Participants choose the least cost combination of pollution abatement and permit purchases.

3. The compliance strategy of any one participant does not seriously impact the behavior of the market.

4. Decision-making costs are insignificant.

5. All market participants are risk neutral.

All of these assumptions are embedded in the MPMS linear program formulation and the decision-making processes employed in the AUSM pollution control module. Although some of these assumptions are generally not valid for a system of regulated utilities, the market simulations can reveal the importance of each assumption in modeling the system behavior. Additionally, observing the modeled behavior can lead to creative ways of designing the market system to reduce the impact of market imperfections on the cost efficiency of the system. Theoretically, the market solution should be independent of the modeling technique employed. Differences in the market solution can be attributed to the direct role that capacity addition and dispatching strategies play in a pollution control program and to the loss of important individual plant characteristics in the aggregation routines employed in generating the MPMS exogenous inputs.

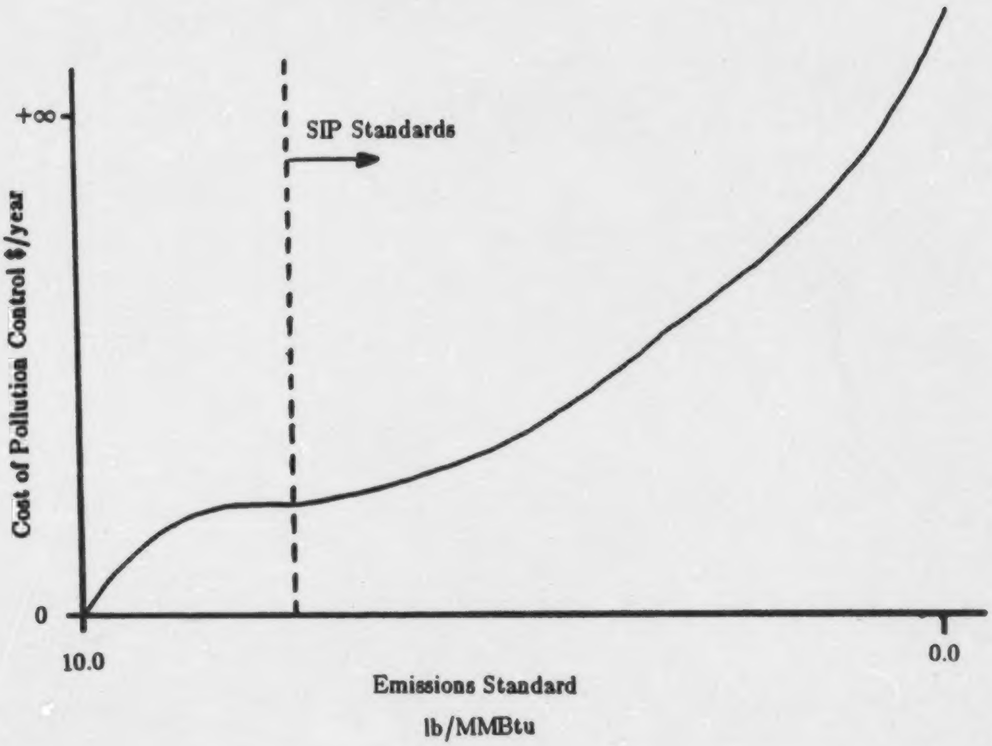
5a.2.2 Cost Curve Generation

To determine the marginal cost curve for various levels of pollution abatement for individual generating units, the pollution control module employs a parametric analysis on each unit's SO_2 emission standard. The total levelized cost of pollution abatement (fuel cost, capital cost of pollution control devices, and variable cost of pollution control) for various emission levels is determined for each unit. Cost curves are generated for all State Implementation Plan (SIP) plants and New Source Performance Standards (NSPS) plants that do not have scrubbers. Units conforming to the NSPS with post combustion removal requirements have very high marginal costs of pollution abatement and, therefore, it is assumed that they do not participate in the market. An analysis of power plants in the State of Illinois indicated that NSPS plants with scrubbers did not retrofit the scrubber even under a stringent SO_2 emissions cap [5]. Typically, the pollution control module makes three attempts at obtaining the segments of a unit's cost curve, although up to five attempts are made for the units with SIP standards greater than 5.3 lb/MMBtu. It is assumed that the SIP standard is the minimum treatment level for each unit. Assuming a minimum treatment level for all dischargers simplifies the market analysis, because it generally removes the concave portion of a discharger's cost curve.

Figure 5a-1 shows a typical cost curve for an uncontrolled discharger. The cost curve can be divided into two regions. At low removal levels the curve shows decreasing marginal costs for pollution abatement. At higher removal levels marginal costs are increasing. SIP regulations generally place dischargers in the convex portion of the cost curve. Assuming that SIP standards are a minimum treatment level usually eliminates the decision to remove all or none of the pollutant from the analysis.

Figure 5a-1

EXAMPLE OF COST CURVE CONCAVITY AT LOW LEVELS OF POLLUTION ABATEMENT



Additionally, when necessary, the market analysis is easily handled by piecewise linearization.

Instances do occur when a portion of a discharger's cost curve is concave or when the cost curve has discontinuities. The discontinuities are usually small and typically occur between coal switching decisions. The size and location of the discontinuities and concavities are highly dependent on the coal data base. The market routines assume that discontinuities in the cost curves do not exist. Market routines remove concavities in the cost curve by eliminating the operating points that created the concavities. Concavities are frequently attributed to the economies of scale of scrubber construction. Figure 5a-2 demonstrates the procedure used by the SORT method in translating a cost curve with a concavity into a convex cost curve. Concavities have little effect on the selection of pollution control options in the FUTURS method because a two-step test is employed in determining the level of pollution abatement selected by a market participant. Not only must the marginal cost of pollution abatement be equal to the permit price but the unit must incur a total cost savings by selecting to reduce its emissions rather than simply complying by purchasing permits in the market.

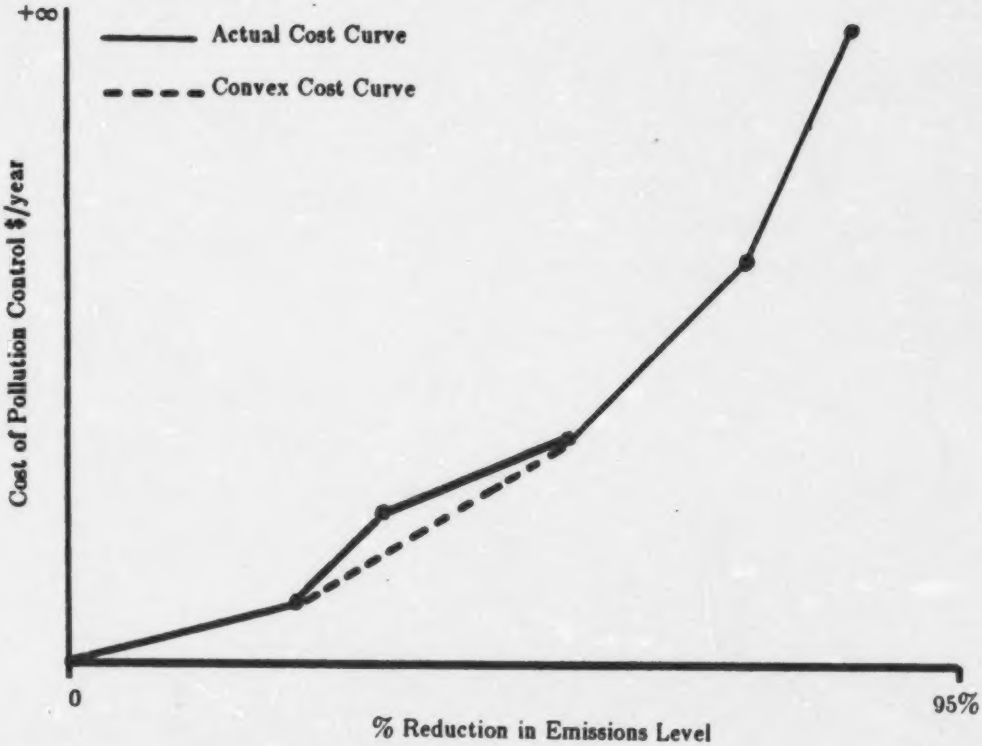
Frequently a discharger has a suboptimal base point for its cost curve. Under this condition it is beneficial for a plant to enter compliance because a cost savings is incurred by switching coal suppliers. Suboptimality of the default operating point for a unit occurs because the pollution control module assumes that a unit can only switch coals if it is required to meet a new emissions standard. "Free" emission reductions are tracked by the market routines. The portion of the emissions reduction that is obtained without additional expense is presented in TDP report 810. It is left up to the user to determine if the free emissions reduction has such a significant effect on the market simulation that the simulation is invalid.

5a.2.3 The SORT Market Simulation Technique

5a.2.3.1 Overview

The SORT technique simulates an SO_2 permit market by transforming individual unit cost curves into a statewide SO_2 permit demand curve for the utility system. Using the emissions cap for the state and the permit demand curve, the pollution control module chooses the pollution control strategy and

Figure 5a-2
REMOVAL OF COST CURVE CONCAVITIES USING THE SORT METHOD



permit purchases/sales for each market participant.

5a.2.3.2 The SORT Method

The SORT method uses a three-step approach to choose pollution control strategies for each individual discharger in the state. First, the pollution control module generates a pollution control cost curve for each discharger. Figure 5a-3 shows several cost curves for selected generating plants in Illinois. A typical cost curve has three segments. These cost curves are crude approximations of each discharger's true pollution control costs. By sacrificing computational efficiency, a more detailed cost curve could be obtained; however, using more refined cost curves would only improve the cost efficiency of a market system over other management strategies. After completion of the generation of a discharger's cost curve, the marginal cost of pollution abatement is calculated for each line segment of the cost curve. The marginal cost curve is a simple step function of the slope of each line segment of a unit's cost curve. After all the marginal cost curves are generated, a sorting technique ranks each pollution control option based on the marginal cost of implementing the compliance strategy. Arranging compliance strategies in a merit-order fashion transforms the individual marginal cost curves into the permit demand curve for the system. The demand curve for a case study of Illinois is shown in Figures 5a-4 and 5a-5. Finally, based on the number of permits to be allocated to the market participants in the state (assumed to be equal to the TDP emissions cap), the market routines select pollution control strategies for each discharger. Compliance strategies with a marginal cost less than or equal to the marginal cost of the step of the demand curve that intercepts the emissions cap are implemented in the simulation. Compliance options for the dischargers shown in Figure 5a-3 are listed in Table 5a-1.

5a.2.3.3 Limitations of the SORT Method

Although the SORT method is a very powerful technique, this market simulation procedure has some limitations. Besides the five assumptions mentioned, several other simplifications are required to simulate a permit market using only the cost curves of individual dischargers. In general, the SORT method assumes that the environmental system is static. The cost curves generated by the pollution control module represent the annual levelized cost of meeting an emissions constraint for a single generating

Figure 5a-3
1987 PRESENT VALUE ANNUAL LEVELIZED POLLUTION CONTROL COST
FOR SELECTED ILLINOIS POWER PLANTS

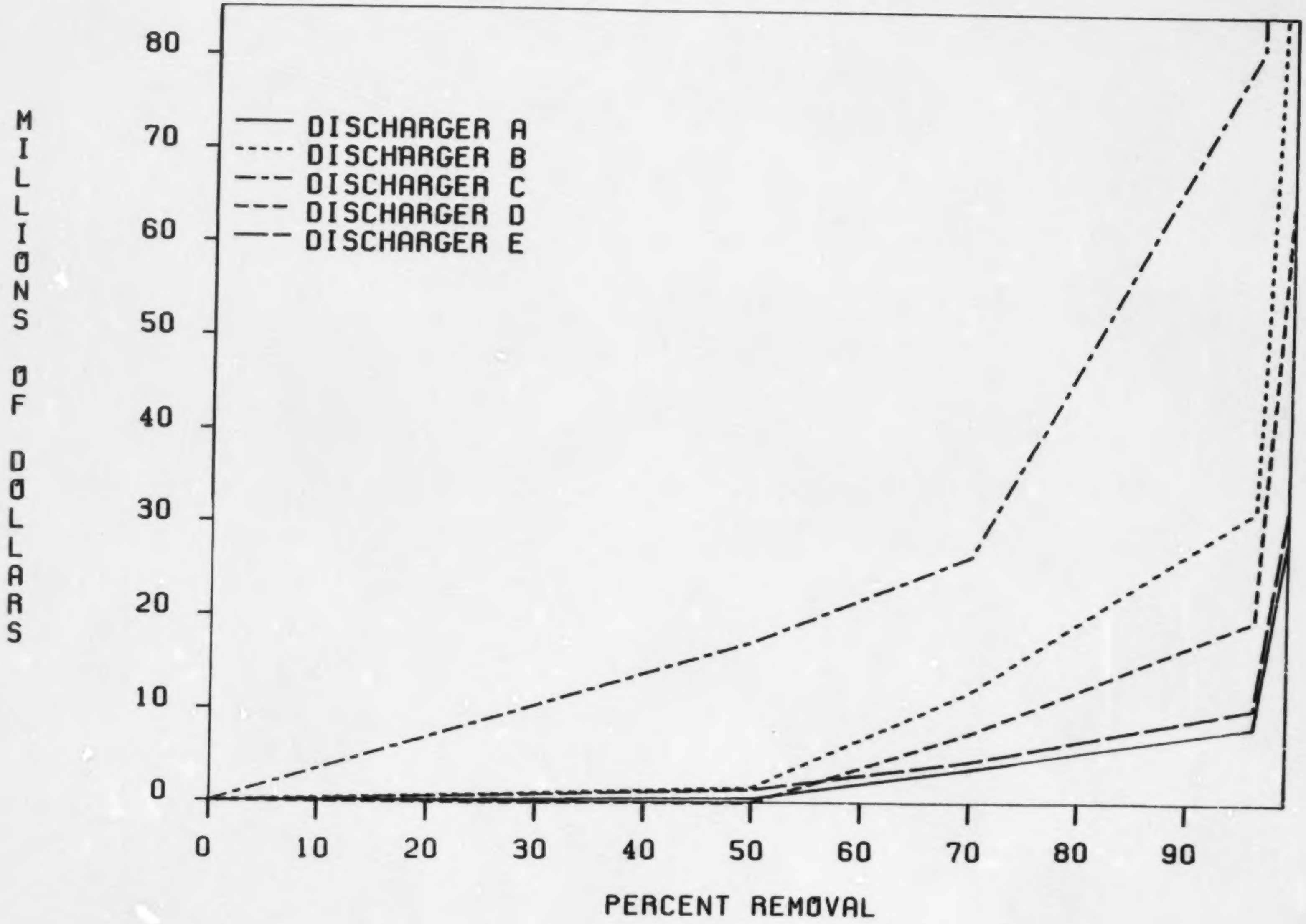


Figure 5a-4

THE ILLINOIS SO_2 PERMIT DEMAND CURVE

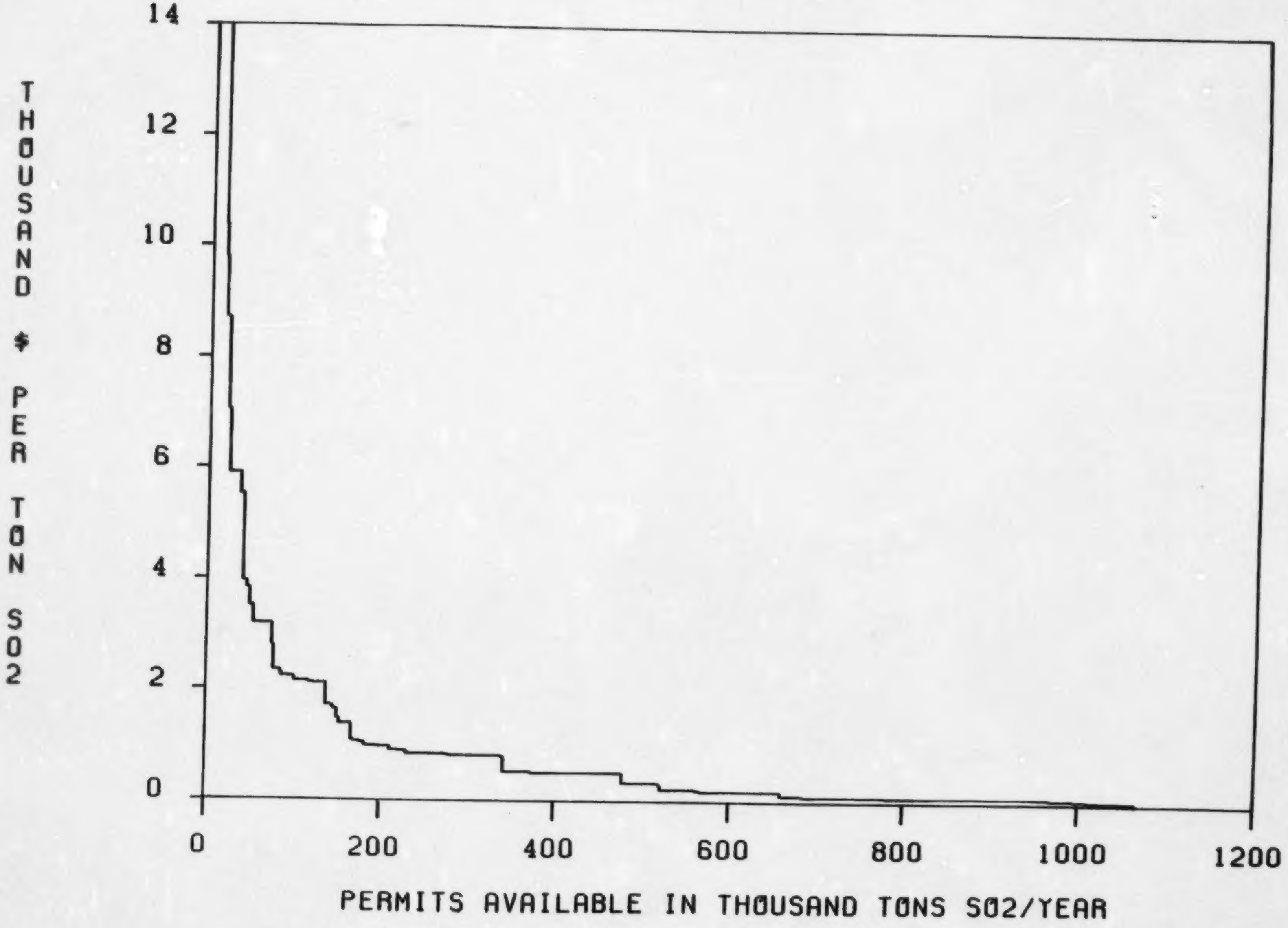


Figure 5a-5
ENLARGEMENT OF THE ILLINOIS PERMIT DEMAND CURVE

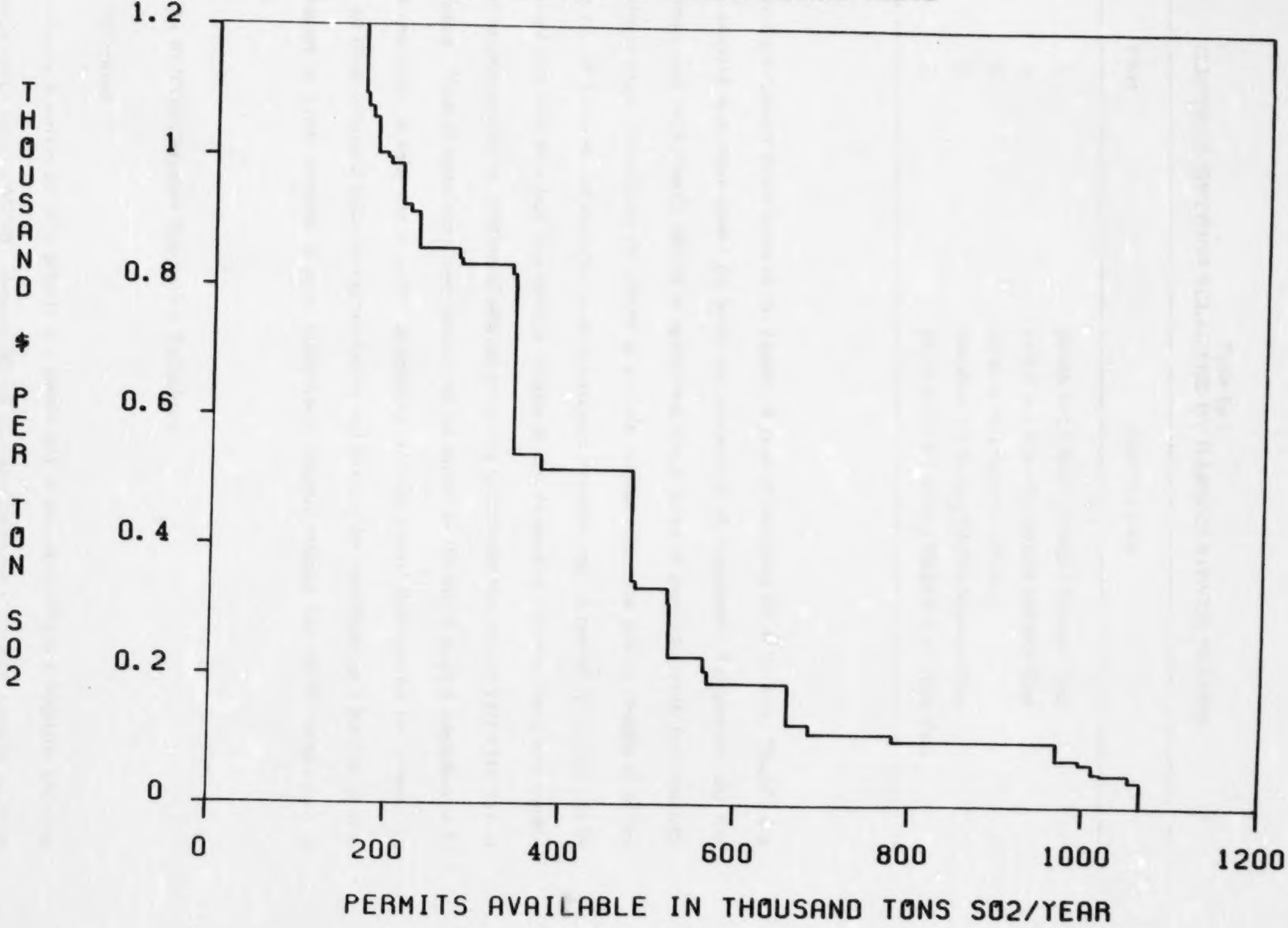


Table 5a-1
CONTROL OPTIONS SELECTED BY ILLINOIS POWER PLANTS

Plant	Control Option
A	Switch to 1.3 lb-SO_2/MMBtu Midwest Coal
B	Switch to 1.3 lb-SO_2/MMBtu Midwest Coal
C	Scrub at 92% Removal Efficiency
D	Switch to 1.3 lb-SO_2/MMBtu Midwest Coal
E	Blend (87%) 0.7 lb-SO_2/MMBtu Applachian Coal

unit assuming a capacity factor based on the number of years of remaining life of the unit. Therefore, it must be assumed that plant production levels are independent of compliance. Furthermore, the cost curves reflect only costs directly related to operational modifications at generating units, fuel switching and scrubbing costs. Considering the system as a whole, options other than process changes or adding pollution control hardware are available to meet a regional emissions cap. A control option that can be implemented with very little lead time involves changes in unit dispatching patterns. Long term compliance options include capacity additions of selected generating technologies that lack or have a low level of SO_2 emission. None of these compliance options are considered by the SORT market simulation technique; it only looks at units one at a time in selecting pollution control strategies for the system. To account for these additional pollution control options and to recognize compliance as a function of temporal changes in power demand, a more sophisticated analysis utilizing the MPMS preprocessor is required.

5a.2.4 The FUTURS Market Simulation Technique

5a.2.4.1 Overview

Simulating a market for SO_2 permits is a simple task if one has available a long-term planning, optimization model such as MPMS. Because MPMS can simultaneously investigate capacity addition, dispatching, power pooling, and pollution control compliance options while minimizing the present value of all system costs (capital and operating) over the planning horizon, the FUTURS method can overcome many of the limitations of the SORT market simulation. The FUTURS method employs MPMS to simulate a dynamic market for emissions permits. The value of the permits, (essentially an emissions charge that would obtain the desired level of SO_2 emissions) along with capacity factor projections and a capacity addition plan are utilized by AUSM in simulating the market system on a plant or unit level.

5a.2.4.2 The FUTURS Method

MPMS, because it is a linear program, can provide the user with valuable information about the cost penalty of constraining the performance of the power supply system. Emission constraints are of particular interest to this analysis because they are representative of environmental regulation. For the MPMS formulation, the Lagrange multiplier (λ) of the emissions cap constraint is defined as the change in the present value of all system costs for removing an additional ton of pollution in a time period of the analysis. In other words, λ is the marginal cost of sulfur dioxide removal for the system. Under a market system where dischargers treat until their marginal cost equals the price of a permit, λ is the value of an SO_2 permit. Therefore, besides developing a compliance plan for the system, MPMS simulates a dynamic market for SO_2 permits. λ, for each time period, gives the present value of securing an emissions permit in the base year of the simulation for a future time period. The value of λ for each time period can be summed to obtain the present value of securing a perpetuity right to emit SO_2. This value is (or at least approximates) the market clearing price for transferable discharge permits in a single price auction.

An improvement to this method would include the use of capacity factor projections from the MPMS simulation in calculating the pollution abatement cost curves. Using MPMS capacity factor projections in calculating the abatement cost curve of each individual discharger, enables AUSM better to capture the role that dispatching patterns, capacity additions, and the early retirement of plants play in the over-all system compliance strategy in the individual unit pollution abatement cost curves. This option requires further analysis prior to implementation.

The FUTURS market simulation technique directly utilizes the market clearing price for permits obtained from the MPMS analysis. Again, the AUSM market simulation utilizes the pollution control module to generate a cost curve for each discharger. As the cost curve is generated, the marginal cost of each linear segment of a discharger's cost curve is calculated. The marginal cost of pollution abatement is compared to the market clearing price for SO_2 permits. The combination of pollution abatement and permit purchases that provides the greatest total savings to each discharger is selected as the control strategy.

5a.2.4.3 Limitations of the FUTURS Method

The FUTURS market simulation has one major shortcoming in predicting the behavior of individual generating plants under the market system. The cost curves generated by the pollution control module reflect the cost of pollution abatement at each unique generating plant. The level of aggregation employed in the MPMS model eliminates many of the compliance options that uniquely define a system's true permit demand curve. The values of the dual variables tends to be relatively insensitive to the emissions cap at low levels of pollution abatement, but they are extremely sensitive to the emissions cap for high levels of emissions reduction. The behavior of the dual variables is typical of lumpy problems modeled as linear programs. Due to the sensitivity problem, the user has little control over the level of environmental quality obtained in the AUSM FUTURS market simulation. For an analysis of Illinois under a emissions cap of 450,000 tons per year, the market clearing price predicted by MPMS was $780/ton. In the AUSM simulation, this permit price resulted in an emissions level approaching 350,000 tons per year. One way of overcoming the problem of exercising better control over the level of environmental quality is to use the capacity factors from the MPMS simulation in generating the cost curves in the pollution control module while using the SORT technique to select pollution control compliance strategies for individual dischargers. Although this approach has not been implemented, it would appear to give the user more direct control of the level of emissions that is attained in the market simulations while overcoming some of the limitations of the SORT technique.

5a.3. Implementation

5a.3.1 AUSM Modifications

The market simulation management scenario option is fully automated and can be initiated by simply turning on the market scenario switch (global scenario parameter 79) and specifying the market scenario parameters. The SORT method requires the user to specify a market year and an emissions cap for the market participants (active coal SIP plants and NSPS plants without FGDs). The market year is the first year in which the cap is enforced. If emissions from NSPS plants, conforming to the scrubbing requirement are substantial, then the emissions cap specified for the market analysis should be less than the total allowable emissions cap for the state. Use of the FUTURS method requires that an analysis using MPMS be carried out prior to the AUSM simulation. Because permit prices are known prior to the AUSM market simulation, the user need not specify an emissions cap for the selection of a pollution control option, but it is advisable to use an emissions cap constraint in the dispatching module to capture any dispatching alternatives that were planned as part of the short-term compliance strategy. The user must specify a percent rollback (state scenario parameter 441) to be used in grandfathering the permits in a FUTURS market simulation. SIP compliance can be carried out in the market simulation provided the SIP compliance date is at least four years prior to the enforcement of the market.

5a.3.2 Performance

The market simulations do not significantly add to the total cost of running an AUSM simulation. However, they do substantially add to the computation effort of the pollution control module. Sample runs using the Illinois Plant Inventory increased the total cost of a simulation by 5 to 10 percent while the time spent in comply increased about 50 percent. The only major disadvantage of the market simulation is that the SORT method does require the use of a substantial amount of storage because the 33 characteristics that define each potential pollution control operating strategy for each unit must be stored until cost curves for all the market participants are available. Storing all this data is necessary so that it is available after the complete regional permit demand curve is formed.

The arrays used by SORT have been dimensioned to handle 115 market participants and 400 SO_2 permit demand curve steps. The 115 unit limit is adequate for all states; however, it may be possible under some scenarios for a state's demand curve to consist of more than 400 steps. If the array dimensions are not adequate, the program continues the market simulation using the first 400 segments of the demand curve and writes an appropriate error message to the pollution control trace. The FUTURS method has no major storage requirements since the permit prices are known prior to the start of the AUSM simulation.

5a.4. An Illinois Case Study

An extensive analysis evaluating a market management strategy as a means of implementing acid deposition legislation was carried out for Illinois [5]. Several capacity addition scenarios (defined in Table 5a-2) and various levels of pollution abatement were investigated. The analysis employed the EPOS module (substituting for the MPMS preprocessor) as an optimizer of the capacity addition schedule and AUSM as a simulator of program impacts.

An example of the permit prices obtained from the EPOS simulations is shown in Figure 5a-6. Under the coal intensive capacity addition scenarios, permit prices are much higher in the first years of the market because capital investments are made for scrubbers under Scenario III while under Scenarios I and II coal switching is the predominant compliance option. Once the capital investments for scrubbers are made, permit prices stabilize. In the later time periods of the simulation, permit prices increase substantially because under a 2 percent growth in power demand, the emissions cap constraint approaches infeasibility.

For all capacity addition scenarios, the market system was more cost-effective than the SIP rollback program with approximately the same level of emissions. Figure 5a-7 shows that the cost savings of a market system over the SIP rollback program during the first 10 years of the simulation is typically 40 to 60 percent. Because more scrubbing occurs under the market program than under the SIP rollback, the consumer fails to see a large portion of the cost savings of the market approach. Figure 5a-8 shows that about half of the cost savings of the market system fails to show through in utility rates because of the return on capital allotted to the utilities for the capital investments made under the market program.

Table 5a-2
CAPACITY ADDITION SCENARIOS

Scenario I:	Unconstrained Additions It is assumed that all nuclear plants currently under construction in the state are licensed and that future nuclear additions are unconstrained. The cost of new nuclear capacity is $1580/KW.
Scenario II:	No Nuclear Additions After 1987 All nuclear plants currently under construction are licensed but future capacity additions are restricted to base load coal plants.
Scenario III:	Nuclear Moratorium 1984 All nuclear plants that were not licensed and operating as of January 1, 1984 are canceled and all future capacity additions are restricted to base load coal plants.
Scenario IV:	50 Percent Increase in Nuclear Construction Costs All nuclear facilities currently under construction in the state come on-line as scheduled but future nuclear additions cost $2370/KW.

Figure 5a-6
THE 1987 PRESENT VALUE OF SECURING A PERMIT TO EMIT SO_2 IN THE STATE OF ILLINOIS

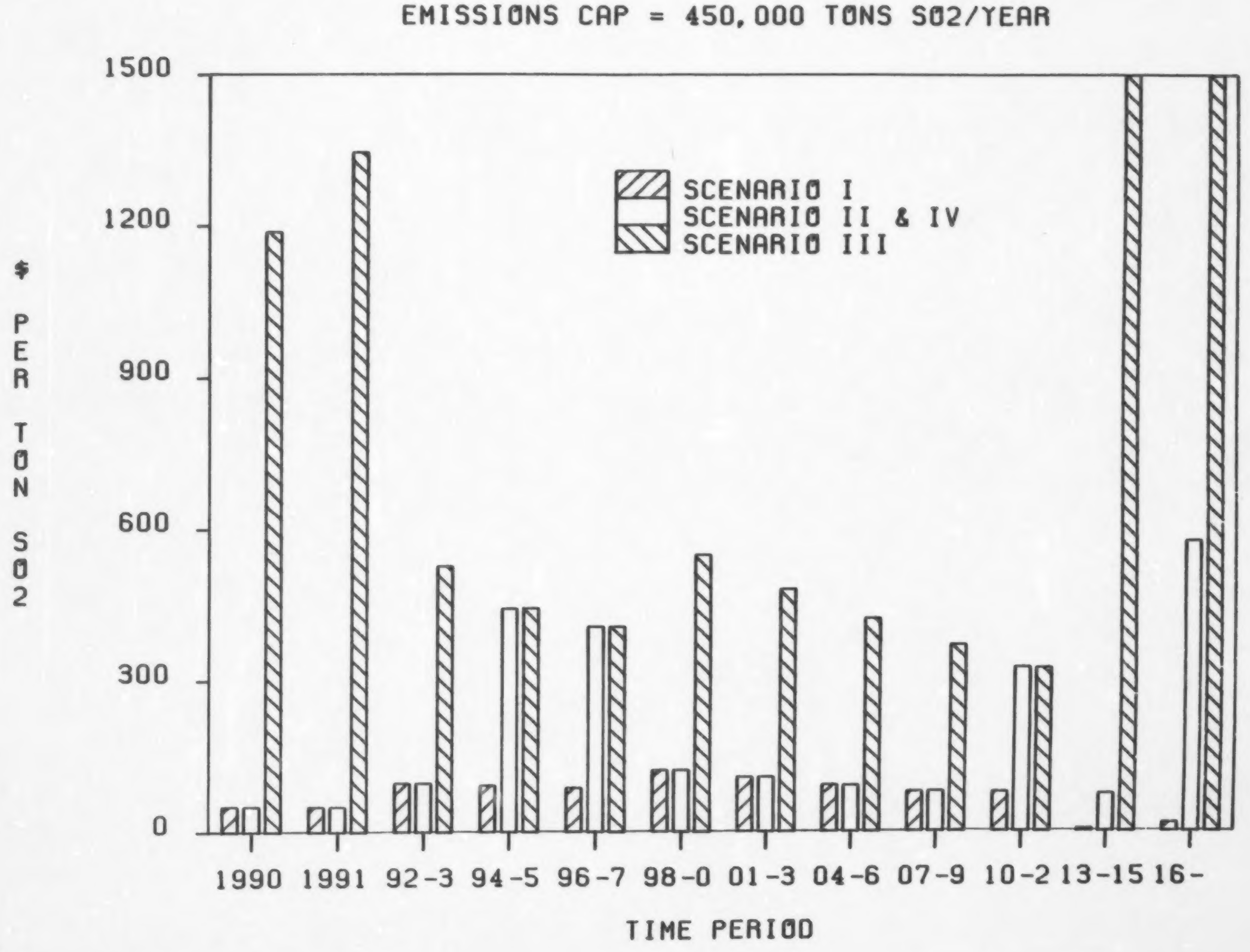


Figure 5a-7
INCREASE IN THE PRESENT VALUE OF TOTAL SYSTEM COSTS DURING 1990-1999
UNDER A 450,000 TON EMISSIONS CAP

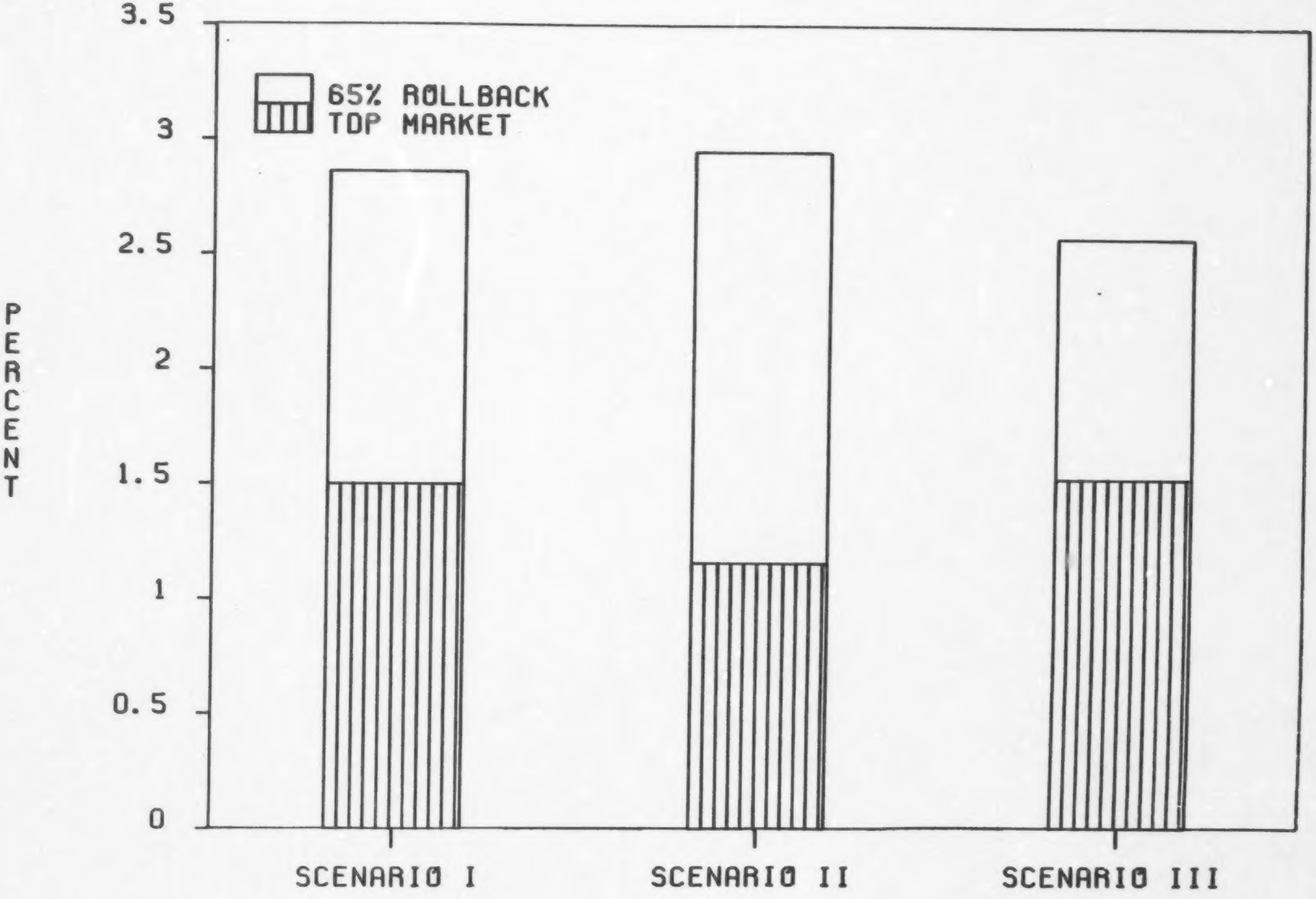
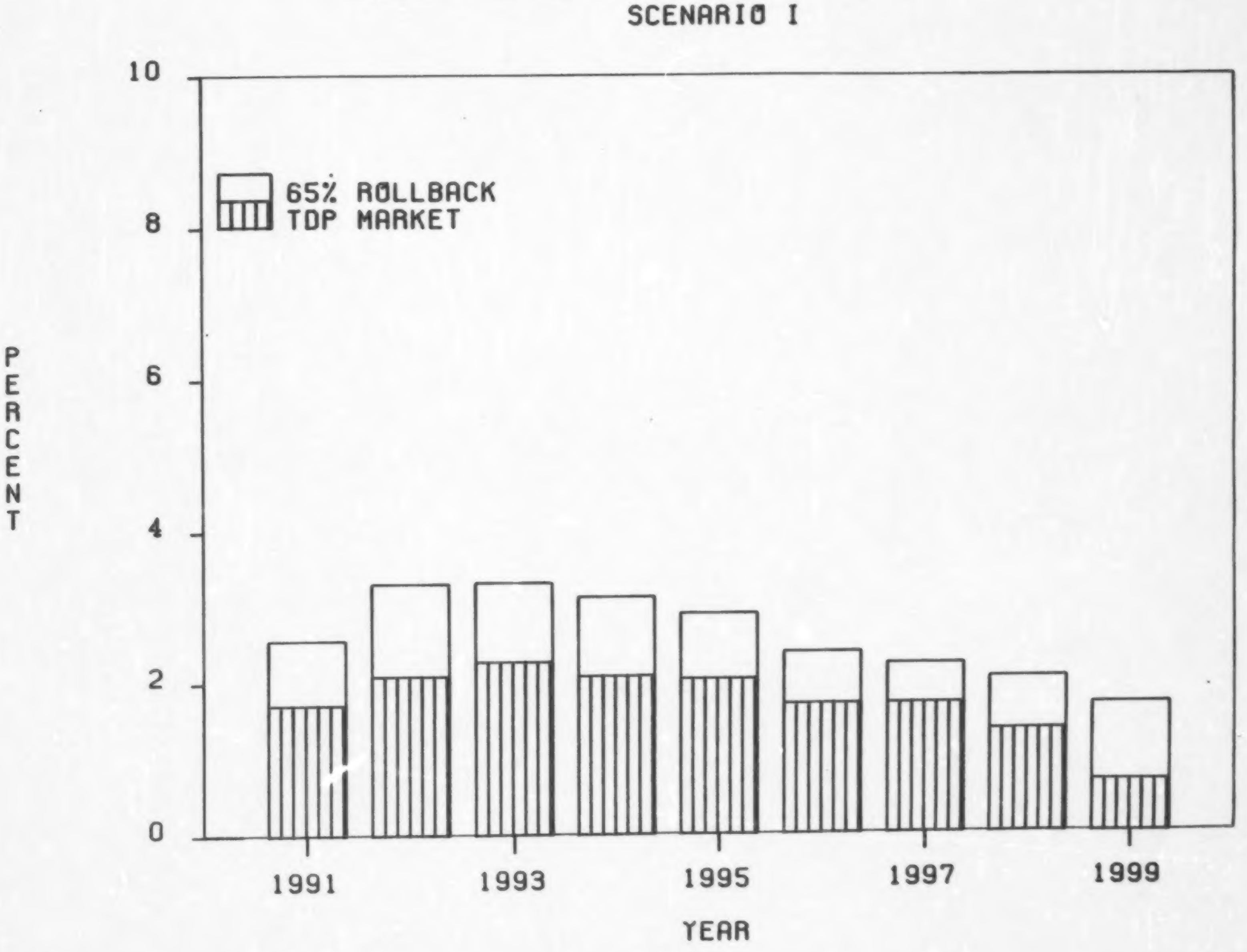


Figure 5a-8
INCREASE IN THE AVERAGE COST OF SERVICE
FOR THREE DIFFERENT MANAGEMENT PROGRAMS



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5b. COST OF FUEL OIL BY SULFUR CONTENT

by

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SO_2 emissions from oil-fired power plant boilers, which are more common in the northeast than elsewhere, can be reduced by firing low sulfur fuel oil. Such fuel oil is available from several sources: low sulfur ("sweet") crude, desulfurized oil, and blending of oils of different sulfur contents to produce an oil of any desired sulfur content. Actual SO2 reduction depends, naturally, on the sulfur content of oil currently in use and the content of the low sulfur oil but reductions are potentially considerable.

There are several technologies for desulfurization fuel oil: hydrodesulfurization, partial oxidation, and chemically active fluidized bed. The last two produce fuel gas while the first results in liquid fuel oil. Other processes are available but generally result in little reduction in sulfur content. These are heavy gas-oil desulfurizing, residual visbreaking, residual upgrading, visbreaking, fluid coking, and delayed coking. Only hydrodesulfurization is covered in this report.

The cost of desulfurizing resid (No. 6 fuel oil) depends on two things: the amount of sulfur to be removed and the metals content of the resid (which is determined by the crude from whence it came). Greater sulfur removal implies a more complex process, with higher capital investment and higher variable costs. Higher metals content implies either more rapid consumption of catalyst and/or higher capital cost for demetalizing facilities. Estimates of the cost of desulfurizing fuel oil range from $1.31/bbl (25 percent reduction of Ceuta crude) to $8.38/bbl (98 percent reduction of Cold Lake crude), with costs given in 1982 dollars.

Fuel oil of varying sulfur contents is currently traded in the market-place. Oil with relatively high sulfur content is likely to be atmospheric resid derived from refining crude with high sulfur content. As sulfur content of the fuel oil falls, less oil is supplied by straight refining and more results from blending high and low sulfur oils. At the low end of the sulfur spectrum, nearly all fuel oil is the result of desulfurizing.

Price data do not distinguish the source of fuel oil -- they only report price by sulfur content. Reported prices cover sulfur contents ranging from less than 0.3 percent to "high sulfur" fuel oil, the content of which exceeds 3.0 percent. As a first approximation, the 1982 price of fuel oil varies as a function of sulfur content according to the following equation:

$$\text{Price/bbl} = \$28.00 \times (\text{sulfur content in \%})^{-0.111471}$$

The cost impact of switching to lower sulfur fuel oil depends on the amount of desulfurization sought. Sue 3.8 percent as the base case, the cost of moving to 1.6 percent oil is 1.9 mills/kWh. SO_2 removal varies from $155/ton (1.6 percent oil) to $785/ton (0.1 percent oil).

5b.1 Introduction

The States of New York and Pennsylvania contain a relatively large number of electric generating plants which are fired primarily with No. 6 fuel oil. Most of these plants are older facilities currently used to cover peak demand, although there are several newer, larger facilities capable of base load service.

One method of reducing SO_x emissions from these plants is to fire low sulfur fuel oil in place of high sulfur fuel oil. Such a change requires no major modification to existing plants. As a rule, however, low sulfur fuel oil is more expensive.

Low sulfur fuel oil can be derived from one of several sources: 1) it can result from the refining of crude oil which is inherently low in sulfur content, or 2) it can be derived from high sulfur fuel oil via desulfurization. this last route results in cost increases since complex chemical processes must be used in removing the sulfur.

While sulfur contents as low as 0.1 percent by weight are achievable, the cost of removing so much sulfur can be quite high. However, the amount of sulfur removed is not the only determinant of cost. Metals content (nickel and vanadium) of the feedstock, which is determined by the crude oil itself, has a heavy influence on desulfurization cost.

Low sulfur fuel oil is currently available in sufficient quantities and has a well defined price structure. Both prices and quantities are reported in the trade press and official U.S. Department of Energy publications. These sources are sufficient to allow a first approximation of the functional relationship between sulfur content and price.

Desulfurizing oil changes some of the oil's properties. In particular, the oil becomes lighter (lower specific gravity) and has a higher heat value per pound. On balance, the two effects are sufficient to cause the heat value per barrel to fall. The effect is that a larger volume of oil must be fired to achieve the same level of boiler output.

The purpose of this study is to investigate the cost of fuel oil as a function of sulfur content and to evaluate the effects of switching to low sulfur oil in terms of effects on SO_2 emissions and on the costs of operating a power plant with lower sulfur oil.

The scope of this study is to evaluate impacts on plants like those in New York and Pennsylvania in terms of cost, cost per kWh, and cost per ton of SO_2 removed. There are impacts which are outside the scope of this work which nevertheless have a material bearing on some of these issues: Use of different fuels can have impacts on O&M costs of some plant equipment. Transition to new fuels may require modifications to some storage facilities.

One desulfurization process, hydrodesulfurization, has been singled out for special investigation. this part of the study is presented separately in Section 5b.6. Costs of desulfurized oil have been partially developed with this process in mind.

This study has been divided into the following chapters:

Section 5b.2 Prices of Low Sulfur Oil
Section 5b.3 Desulfurization Capacity
Section 5b.4 Properties of Low Sulfur Fuel Oil
Section 5b.5 Emissions & Cost Impacts of Switching to Low Sulfur Fuel Oil
Section 5b.6 Hydrodesulfurization

The underlying rationale is that although a variety of prices are reported for fuel oils by sulfur content, the relationship between the two has not yet been explained in sufficient detail to generalize the price/sulfur connection. Hence, price is developed as a function of sulfur content. Whether this price will remain stable in the face of increased utility demand for lower sulfur oil depends at least in part on the desulfurizing capacity available currently. Desulfurizing fuel oil changes some of its properties. These changes impact rates of consumption. Finally, the impacts of a change can best be studied via use of two model plants.

5b.2 Prices of Low Sulfur Fuel Oil

This section presents a review of the prices of fuel oils as a function of sulfur content by weight and other factors such as metals content. The objective is to determine whether there is a relationship which expresses price as a function of sulfur content in a simple way.

There are two sources of low sulfur fuel oil: 1) reside derived from low sulfur crudes, and 2) fuel oil derived from hydrodesulfurization (HDS) of high sulfur resid. In either case, the discussion is confined to the price of No. 6 fuel oil.

The price of interest is the market price of fuel oil, which represents a composite of fuels resulting from both low sulfur crudes and HDS. While some buyers may specifically purchase one or the other for reasons of their own, it is not possible to know a priori whether the resid any customer buys comes from one or the other. In particular, for analysis of fuels sold to utilities, it seems wiser to examine the market price.

The approach of this chapter is to examine market prices as reported in the open literature, to compare these prices with engineering estimates of the cost of cleaning up fuel oil via HDS, and to provide an equational representation of the price of fuel oil as a function of sulfur content. This material will then be used in later chapters to evaluate the impact on air emissions resulting from the use of low sulfur oil in utility boilers.

5b.2.1 Review of Price Data

This section contains a review of the available data on the price of fuel oil as a function of sulfur content by weight. These data were assembled from two major sources:

1) U.S. Department of Energy/Energy Information Administration
2) Energy User News (Fairchild Publications, New York, N.Y.)

While there appears to be general agreement among the sources that the price of fuel oil varies inversely with sulfur content, direct comparison of prices is difficult due to differences in assumptions and reporting conventions.

Three sets of publications were used:

1) Monthly Energy Review, December 1983. (DOE/EIA-0035(83/12(2)))

2) Cost and Quality of Fuels for Electric Utility Plants, 1982 Annual (DOE/EIA-0191(82))

3) Energy User News (various issues from 1983)

Of these, the EIA publications provide "official" prices inasmuch as they originate from the Department of Energy. Energy User News, however, provides slightly greater coverage in terms of data. This provides an advantage to be discussed below.

All three sets of data differ with respect to sulfur content of fuel oil. Only Energy User News gives price by specific sulfur content, others providing rages. Comparisons of sulfur content reporting are show in Table 5b.1. Although one might suspect that the sulfur contents given by Energy User News are really nominal values standing for ranges of values, no evidence could be developed for or against this feeling.

Fuel oil prices also differ with respect to purchaser. Those purchasing wholesale (i.e., purchase for resale) tend to pay less than those purchasing at the retail level. End users, such as utilities, purchase at this level. Only Monthly Energy Review provides prices paid by utilities only. Energy User News is ambiguous on this point and it is assumed that prices represent an average.

Given the scope of this study, it was decided to present prices in terms of normalized values. Normalization was accomplished by dividing the price at each sulfur content level by the price at the highest reported level to provide the premium paid for low sulfur fuel oil as a percent of the price of high sulfur oil. This method has the additional benefit of allowing direct comparison over time without having to normalize prices to a given base year. The formula used to do this was:

$P_i = (\text{price}_i)/(\text{base price})$

where:

P_i = normalized price for sulfur content i

price_i = reported price for sulfur content i

base price = price for high sulfur oil

Prices provided in Monthly Energy Review were normalized to the average price. This was done for two reasons: 1) the number of sulfur content intervals is small -- indicating that there is nothing special to be learned about the price as a function of sulfur content; 2) the number of years covered is large -- making these data useful in evaluating the price of low sulfur oil over time.

Table 5b.1 METHODS OF REPORTING SULFUR CONTENT

Source	Monthly Energy Review	Cost and Quality of Fuels for Electric Utilities	Energy User News	
Sulfur Content Categories	0.00% to 0.30%	less than or equal 0.30%	0.3%	1.75%
	0.31% to 1.00%	0.31% to 0.50%	0.5%	2.4%
	greater than 1.00%	0.51% to 1.00%	0.7%	2.9%
	average	1.01% to 2.00%	1.0%	high sulfur
		2.01% to 3.00%	1.1%	

Tables 5b.2 through 5b.5 give the prices and normalized prices of low sulfur fuel oil as presented by each source. These data are given by year as well as sulfur content in Table 5b.2 and by month (for selected months) in Tables 5b.4 and 5b.5. Data in Table 5b.2 are end user (utility) prices only. Table 5b.5 also provides the means, standard deviations, and coefficients of variation for the normalized prices in order to provide an estimate of the stability of the price premium for low sulfur fuel oil over the time given (roughly one year).

Figure 5b.1 is a plot of the values from the tables preceding it. This allows visual comparison of data. It is interesting to note that there is fairly good agreement among the sources. Data were ploted for 1982, in the case of Monthly Energy Review data, and average data were plotted for Energy User News data.

Additionally, the Energy User News averages were used to estimate a power curve relationship between sulfur content and price premium.

Averages were used as data inputs due to the low coefficients of variation (see Table 5b.4b) and the attendant reduction in computation due to that approach. The equation represented by the regression line is:

$$y = 1.073257\, x^{-0.111471}$$

where:

y = price premium as a multiple of high sulfur price
x = sulfur content by weight

R^2 was equal to 0.88 for these data. This implies that the relationship between sulfur and premium is linear in logs.

The power curve relationship suggests itself for several reasons: First, it is a simple relationship and is therefore suitable to the first order approximation sought in this study. More complex mathematical formulations, while potentially delivering greater precision, do so only at the expense of a greater number of high quality data points. Second, a power curve is also a Cobb-Douglas curve and, accordingly, allows direct inference of the elasticity of price with respect to sulfur content -- allowing all of the useful analyses flowing from constant elasticity formulations. To see this, consider the general from of the equation fit to the data:

Table 5b.2 LOW SULFUR FUEL OIL PRICES TO END USERS FROM MONTHLY ENERGY REVIEW

Year	$/bbl				Normalized to Average			
	0.0% to 0.3%	0.31% to 1.0%	more than 1.0%	avg.	0.0% to 0.3%	0.31% to 1.0%	more than 1.0%	avg.
1979	21.21	19.33	16.44	18.67	1.136	1.035	0.881	1.000
1980	31.13	27.59	22.11	26.09	1.193	1.057	0.847	1.000
1981	39.31	33.69	28.57	32.50	1.210	1.037	0.879	1.000
1982	36.34	30.71	25.82	29.08	1.250	1.057	0.888	1.000

Table 5b.3 PRICE OF LOW SULFUR FUEL OIL FROM COST AND QUALITY OF FUELS FOR ELECTRIC UTILITY PLANTS 1982 ANNUAL

	$/bbl	normalized
0.30% or less	34.74	1.363
0.31% to 0.50%	37.11	1.456
0.51% to 1.00%	31.34	1.230
1.01% to 2.0%	26.79	1.051
2.01% to 3.0%	25.71	1.009
over 3.05	25.48	1.000
average	29.81	1.170

Table 5b.4 FUEL OIL PRICES FROM ENERGY USER NEWS

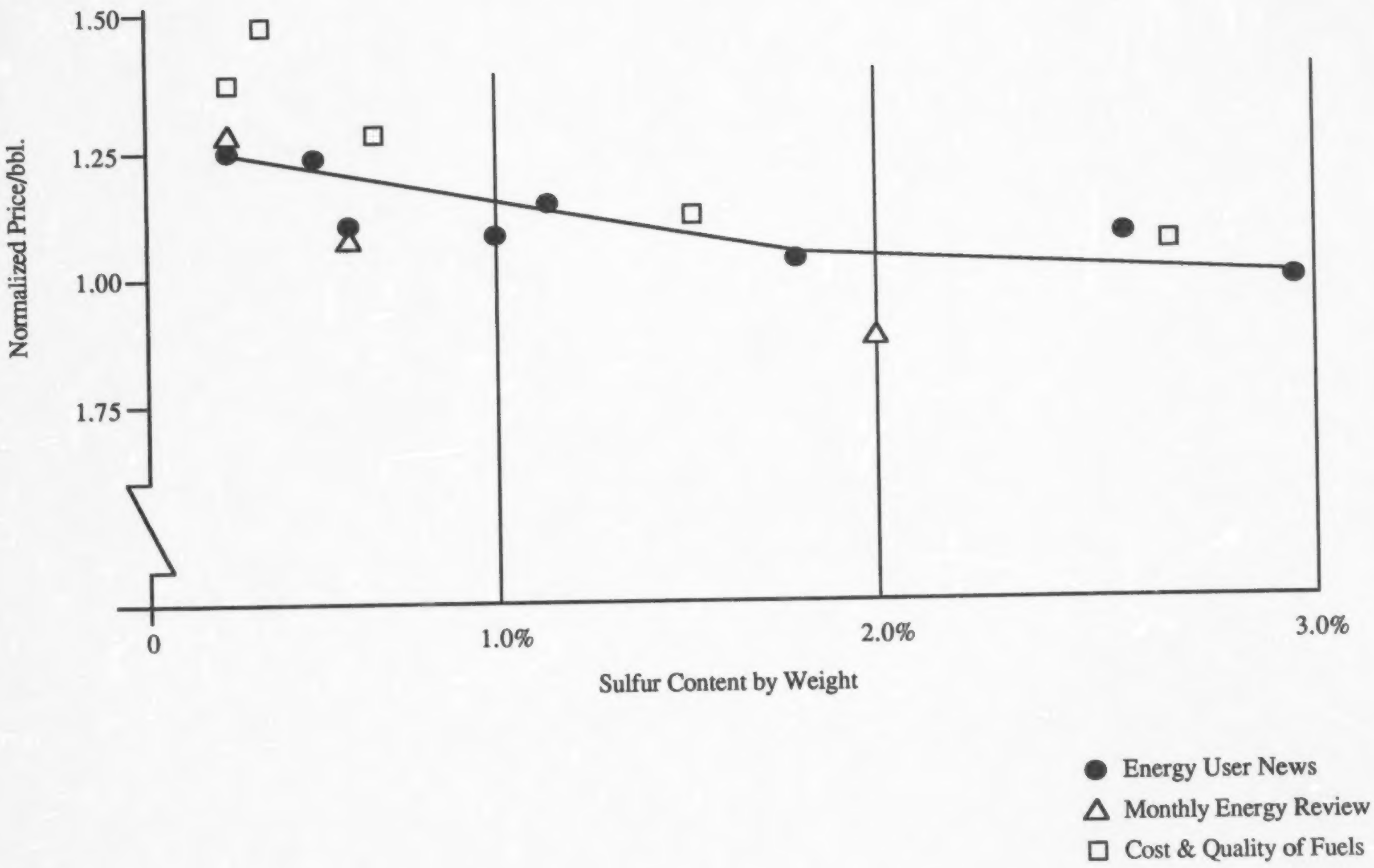
	1982 Dollars per Barrel								
	0.3%	0.5%	0.7%	1.0%	1.1%	1.75%	2.4%	2.9%	High Sulfur
7/82	34.20	33.70	29.90	27.29	28.77	27.24	27.87	25.95	27.40
8/82	32.95	32.63	28.90	26.63	28.77	26.74	26.62	24.95	26.15
9/82	32.95	32.13	28.90	26.63	28.77	26.74	26.62	24.95	26.15
10/82	34.08	33.12	28.90	28.58	31.29	27.27	27.12	25.45	26.65
5/83	31.24	30.78	27.20	27.48	27.51	25.70	26.37	24.45	26.00
6/83	31.24	31.28	27.20	27.64	27.51	25.55	26.54	23.95	26.00
7/83	32.24	32.28	27.20	28.07	27.51	25.74	26.54	23.95	26.00
8/83	32.50	32.28	28.70	29.29	27.51	26.97	27.54	25.45	27.00
9/83	32.30-	32.43	28.70	28.56	28.35	25.74	28.54	25.95	28.00

Table 5b.5 NORMALIZED PRICES OF LOW SULFUR FUEL OIL FROM ENERGY USER NEWS

Dollars

	0.3%	0.5%	0.7%	1.0%	1.1%	1.75%	2.4%	2.9%	High Sulfur
7/82	1.248	1.230	1.091	0.996	1.050	0.994	1.017	0.947	1.000
8/82	1.260	1.248	1.105	1.018	1.100	1.023	1.018	0.954	1.000
9/82	1.260	1.229	1.105	1.018	1.100	1.023	1.018	0.954	1.000
10/82	1.279	1.243	1.084	1.072	1.174	1.023	1.018	0.955	1.000
5/83	1.202	1.184	1.046	1.057	1.058	0.988	1.014	0.940	1.000
6/83	1.202	1.203	1.046	1.063	1.058	0.983	1.021	0.921	1.000
7/83	1.240	1.242	1.046	1.080	1.058	0.990	1.021	0.921	1.000
8/83	1.204	1.196	1.063	1.085	1.019	0.999	1.020	0.943	1.000
9/83	1.161	1.158	1.025	1.020	1.013	0.919	1.019	0.927	1.000
MEAN	1.228	1.215	1.068	1.045	1.070	0.994	1.018	0.940	
S. DEV	0.038	0.031	0.029	0.033	0.049	0.032	0.002	0.014	
V	0.31	0.026	0.027	0.031	0.046	0.032	0.002	0.015	

FIGURE 5b.1 NORMALIZED FUEL OIL PRICES



y = axb

which in logs becomes

$$\ln(y) = \ln(a) + b \ln(x)$$

Differentiated, this becomes, in turn,

$$\frac{d \ln(y)}{d \ln(x)} = b$$

This is to say that the percentage change in y divided by the percentage change in x is, at a point, b. In other words, the percentage change in price premium of fuel oil divided by the percentage reduction in sulfur is a constant -- in this case -0.111. Thus, each 10 percent reduction in sulfur is a constant -- in this case -0.111. Thus, each 10 percent percent reduction in sulfur content causes a rise of approximately 1 percent in price.

Although this mathematical relationship is a good first approximation, it should be used guardedly. There is nothing to suggest that this relationship is either smooth or stable over time. Indeed, there is some evidence that the relative price of low sulfur fuel oil may be changing upward. Table 5b.2, containing data for the years 1979 through 1982, indicates that the premium for low sulfur fuel oil may be rising relative to the average.

In 1979, the premium for oil in the 0.0 percent to 0.3 percent percent range was 13.6 percent over the average price of fuel oil. By 1982, this premium had risen to 25.0 percent. This could have come about in two ways: 1) it could b that a greater fraction of the fuel oil consumed is of a higher sulfur content and thus lower price, or 2) it could be that the price of low sulfur oil is rising due to higher fractional demand. Other data suggest that the premium is relatively stable with time (see Tables 5b.3 and 5b.5).

Use of the data provided in these tables should be tempered with extreme caution for several reasons:

1) No information is provided about contractual arrangements between refiners and their customers. Utilities commonly enter into such contracts and they tend to temper price increases somewhat.

2) As discussed in the next section, the price of low sulfur fuel oil is determined by two things -- the price paid for crude and the type of crude (and, hence, the cost of desulfurization). If the mix

of crudes and their respective prices vary markedly in the future, the prices of low sulfur fuel oils will also change.

3) Utilities tend to use oil as a fuel in older boilers which are often used as peaking plants. As discussed in later sections, many of the plants in the northeast are very old and may well be replaced. This can shift the balance of supply and demand to reduce the price of low sulfur oil by removing some customers from the marketplace. On the other hand, industrial use of low sulfur fuel oil may well increase -- bringing new customers into the market and causing the price to rise. Without careful study of all segments of this marketplace, it is difficult to suggest how the price might behave in the future

4) Finally, the supply of low sulfur fuel oil might contract. By such a reduction in supply it is meant here that more will be charged for each barrel rather than meaning that the absolute number of barrels available in each market period will be reduced. This could be due to increases in factor prices, increases in the world price of crude oil, or institutional factors.

5b.2.2 Low Sulfur Fuel Oil Via Hydrodesulfurization

This section contains a brief review of the price premiums for low sulfur fuel oil derived from hydrodesulfurization processes (HDS). A further description of the HDS process itself is provided as Appendix A. The focus of the following material is the relationship between the amount of sulfur in the fuel oil and its price, together with the other determinants of price.

Atmospheric resid (generally regarded as No. 6 fuel oil) has a sulfur content determined by the nature of the crude from which it came. This sulfur content varies from 2.12 percent to 4.55 percent by weight. Reduction from these levels to any desired lower level can be achieved by means of HDS. The greater the reduction (i.e., the lower the sulfur content of the resulting low sulfur output), the higher the cost.

Higher costs are due to: 1) more extensive capital equipment, and 2) more input of utilities, catalysts, etc. They are also due to the need to deal successfully with metals (nickel and vanadium) in the feedstock (see Appendix A). Basically, a high sulfur, high metals resid is more expensive to clean up than a low sulfur, low metals resid.

Table 5b.6 is adapted from work done by Catalytic, Inc. (see attribution on table), in which the cost of HDS was studied. The basis for these costs increments was mid-1978. Study of the derivation of these costs indicates that capital investment and items tied to capital investment constitute the chief determinants of cost. Accordingly, these were inflated to 1982 by use of a factor of 1.435 derived from the CE plant cost indices for 1978 and 1982 (218.8 and 314.0, respectively). Table 5b.7 presents the inflated values. These are incremental costs of cleaning up atmospheric resid and should be added to the price of high sulfur fuel oil to get the price of low sulfur fuel oil.

TABLE 5b.6 COST INCREMENTS FOR SULFUR REDUCTION

Crude Source	S%	Percent Sulfur in Ouput			
		1.6%	0.8%	0.3%	0.1%
Ceuta	2.12	$0.91	$2.28	$3.91	$5.28
E. Venezuela	2.38	1.17	2.45	3.93	5.71
Kuwait	3.80	1.80	2.49	3.14	3.51
Khafji	4.36	2.20	2.85	3.60	4.11
Cold Lake	4.55	2.52	3.42	4.53	5.84

Source: Technology Assessment Report for Industrial Boiler Applications: (EPA-600/7-79-179b)

TABLE 5b.7 COST INCREMENTS FOR SULFUR REDUCTION INFLATED TO 1982 BASIS

		Percent Sulfur in Ouput			
Crude Source	S%	1.6%	0.8%	0.3%	0.1%
Ceuta	2.12	$1.31	$3.27	$5.61	$7.58
E. Venezuela	2.38	1.68	3.52	5.64	8.19
Kuwait	3.80	2.58	3.57	4.51	5.04
Khafji	4.36	3.16	4.09	5.17	5.90
Cold Lake	4.55	3.62	4.91	6.50	8.38

To convert the increments presented in Table 5b.7 into price per barrel, the increments are added to the price of high sulfur oil as reported in Energy User News for September 1983. This price was $28.00/bbl. The results are tabulated in Table 5b.8 -- the purpose of which is to relate the cost of desulfurizing oil to figures presented in previous tables.

Figure 5b.2 presents a graphic comparison of values tabulated in Table 5b.8, which are costs of HDS, with values forecast via the equation presented earlier which forecasts the market price of fuel oil by sulfur content. As shown in this figure, forecast values are lower than the cost estimates of Table 5b.8 at a sulfur content of 1.6 percent but gradually enter the range of those forecasts and then exceed the range.

The lesson to be drawn from this figure is that a higher sulfur levels, e.g. 1.6 percent, some fuel oil is untreated atmospheric resid while at lower levels HDS is required to reduce sulfur content. Given that the average sulfur content of domestic crudes is 0.75 percent with a range of 0.19 percent to 1.38 percent, this explanation makes sense. At the extreme low sulfur end of the scale, 0.1 percent, the market generated equation probably suffers from lack of data (the last data point was set at 0.3 percent)

The conclusion to be drawn from this investigation of HDS as a source of low sulfur fuel oil is that the price depends on the nature of the crude from which the resid is derived. Further, the price estimates prepared earlier are reasonable when compared with market prices reported in the literature.

5b.2.3 Selection Of Fuel Oil Price

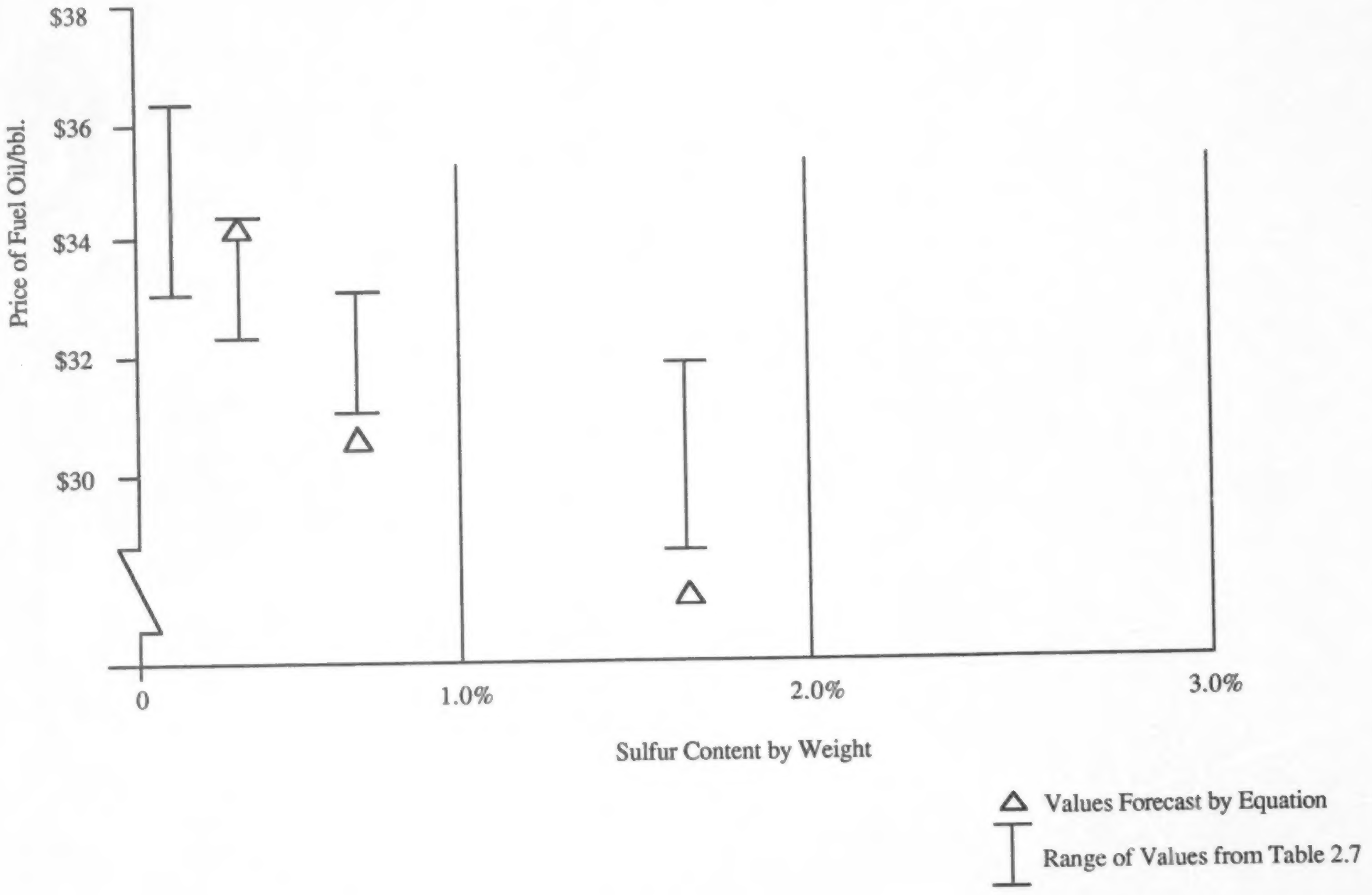
The purpose of this section is to select prices to be used in evaluating the cost of reducing emissions through use of low sulfur fuel oil. Based on the foregoing discussion, it seems reasonable to use values forecast by the equation of Section 5b.2.1 for all sulfur levels except 0.1 percent. At this level, the equation forecasts values which far exceed those forecasted by the engineering analysis results presented in Section 5b.2.2. For reasons discussed in Section 5b.2.2, it seems prudent to use the high end of the range of values given in Table 5b.8. Accordingly, we will use the following prices per barrel for low sulfur fuel oil.

TABLE 5b.8 ESTIMATED COST/BBL OF HDS FUEL OIL

		Percent Sulfur in Ouput			
Crude Source	S%	1.6%	0.8%	0.3%	0.1%
Ceuta	2.12	$29.31	$31.27	$33.61	$35.58
E. Venezuela	2.38	29.68	31.52	33.64	36.19
Kuwait	3.80	30.58	31.57	32.51	33.04
Khafji	4.36	31.16	32.09	33.17	33.90
Cold Lake	4.55	31.62	32.91	34.50	36.38

Source: Table 5b.7 values plus $28.00/bbl

FIGURE 5b.2 COMPARISON OF HDS COST FORECASTS AND MARKET FORECASTS



Percent Sulfur	Dollars per Barrel
high sulfur	28.00
1.6	28.50
0.8	30.80
0.3	34.36
0.1	36.38

It remains to determine whether it seems reasonable to expect these prices to remain constant in the face of increased demand by utilities for low sulfur fuel oil. This question will be the topic of the next chapter.

5b.3 Desulfurization Capacity

The purpose of this chapter is to examine the question of whether there is a capacity restraint which would cause the price of low sulfur fuel oil to rise sharply as a result of increased utility demand. To answer this question, an investigation will be made into the available current capacity, measured in terms of barrels per stream day, and this will then be translated into the number of kilowatt hours which can be serviced by that capacity.

Naturally, there are other buyers of low sulfur oils. If utilities increased demand to the point where they demanded a substantial fraction of available capacity, they would tend to crowd out other buyers. the resulting competition would (at least temporarily) drive prices up -- causing utilities and/or others to seek other strategies for reducing emissions. However, if utilities represent a small fraction of capacity, this will not occur and the prices generated in Chapter 2 can be expected to be representative.

In January 1978 a survey revealed that there is a total desulfurizing capacity of 1,832,350 bbls/day. Of this total, 113,600 bbls/day is HDS capacity. Other technologies make up the difference.

Utilities in New York and Pennsylvania used in this study have a total name plate oil fired capacity of 8,736 MW. At a nominal heat rate of 10,654 Btu/KWh and a load factor of 15 percent (see Chapter 5 for details), this represents a demand of 19.5 x 10^6 bbl/yr at a nominal 6.204 x 10^6 Btu/bbl. Against an annual capacity of 41.5 x 10^6 bbl/yr of HDS capacity this represents 47 percent. Against a total desulfurization capacity of 668 x 10^6 bbl/yr, this represents 3 percent. It seems clear, therefore, that there is no special reason to consider increase in utility demand as constituting a threat to the market price.

Reported utility demand for fuel oil by sulfur content is given in Table 5b.9. According to this table, utilities purchased an amount of fuel oil equivalent to roughly one-third the capacity of all desulfurization facilities. Of course, there is no way of knowing how much of this demand was made up from resids coming from low sulfur crudes. It does seem reasonable, however, to infer that when such sources are added to desulfurization capacity, there is no reason to suppose that utility demand will disrupt the market.

5b.4 Properties of Low Sulfur Fuel Oil

To prepare an examination of the economic and emissions characteristics of low sulfur fuel oils, some of the general properties which determine consumption of fuel oil need to be addressed. The purpose of this Section is to lay out differences in heat value and specific gravity which will lead to different consumption rates measured in terms of barrels.

Generally, desulfurized oils are lighter and thus have a lower heat value per barrel. This heat penalty ranges from 1 percent to 3 percent, with 1.5 percent being a reasonable value for the heat penalty.

Typically, the API° increases as sulfur is reduced, meaning that specific gravity declines. API° and specific gravity are related by the following equation:

$$SG = (141.5)/(131.5 + API^{o})$$

Where:

SG = specific gravity
API° = American Petroleum Insititute gravity

The heat of combustion, measured as Btu/lb, increases as sulfur is reduced. This increase amounts to less than 2%. Coupled with a decrease of 10 percent to 20 percent in specific gravity, this amounts to a net decrease in heat content per barrel. Table 5b.10 summarizes typical important properties of low sulfur fuel oils.

Of interest as well is the fact that low sulfur oils tend to have lower visocities and pour points. the implication here is that less energy will be required to operate pumps and heaters, maintenance should be less and,

TABLE 5b.9 TOTAL UTILITY PURCHASES OF FUEL OIL IN 1982

Sulfur percent	bbls purchased, 1982
0.3% or less	20.3×10^6
0.31 to 0.50	15.7×10^6
0.51 to 1.00	87.7×10^6
1.01 to 2.00	36.2×10^6
2.01 to 3.00	58.5×10^6
over 3.00	0.1×10^6
Total	218.5×10^6

Source: Cost & Quality of Fuels for Electric Utility Plants, 1982 Annual, DOE/EIA-0191(82), August 1983

TABLE 5b.10 PROPERTIES OF TYPICAL LOW SULFUR FUEL OILS BY SULFUR CONTENT

Sulfur content, %	3.8	1.6	0.3	0.1
API°	16.6	20.0	23.4	24.1
Specific gravity	0.96	0.93	0.91	0.91
Btu/lb	n/a	19,110	19.250	19,375
Btu/bbl	$6.388 \times 10^{6*}$	6.245×10^{6}	6.152×10^{6}	6.164×10^{6}

therefore, some categories of operating expenses should be lower. No analysis was conducted for any of these cost savings, however.

In conclusion, conversion to low sulfur oils will require firing of larger volumes of oil to achieve the same heat. These calculations will be carried out in Section 5b.5.

5b.5 Emissions and Cost Impacts of Switching To Low Sulfur Fuel Oil

This chapter contains estimates of likely reductions in SO_2 emissions and their attendant cost impact resulting from switching to low sulfur fuel oil. Impacts have been studied by considering two model plants, an 850 MW base load unit and a 250 MW peak load unit. These were developed after considering the sizes and ages of plants operating in the northeast. All impacts are stated for the plants themselves. No attempt has been made to consider impacts on utilities or on geographic areas surrounding the plants and likely to benefit from any reduction in SO_2.

5b.5.1 Units Of Measure Of Impact

Impacts resulting from switching to low sulfur fuel oil will be measured in several ways. both absolute and incremental measures will be employed. These are:

- o Fuel bill
  - Fuel bill
  - Change in fuel bill
  - Fuel bill per kWh
  - Change in Fuel bill per kWh

- o Sulfur input
  - Sulfur input
  - Change in sufur input

- SO_2
  - SO_2 output
  - Change in SO_2 output
  - Cost per ton of SO_2 removed

Incremental impacts (changes) will be measured with respect to 3.8 percent sulfur fuel oil. Sulfur and SO_2 are measured in 2,000 lb tons. Conversion of specific gravity to measures of weight will be accomplished via the following:

weight = SG(8.33)42

where:

weight = weight/bbl
SG = specific gravity
8.33 =- lbs of water/gallon
42 = gallons/bbl

Dollars are figured in 1982 nominal dollars in concert with oil price determinations given in Section 5b.2.

5b.5.2 Model Plant Studies

In order to evaluate the impact of switching to low sulfur fuel oil, two model plants were considered: an 850 MW base load and a 250 MW peaking plant. Their ages also differ, with the larger plant being a fairly new base load facility and the smaller plant being an old, peaking plant. Fuel use, fuel cost, and emissions are evaluated for both plants. Finally, the cost per kWh and per ton of SO_2 are evaluated.

5b.5.2.1 Size and Age of Oil-Fired Power Plants

In order to construct a test case for use in evaluating the effects on cost and emissions resulting from converting to lower sulfur fuel oil, the size and age of oil-fired plants in the northeast was reviewed. the result of this led to the conclusion that two test cases would be required: one for a relatively small, old plant, and one for a relatively large, young plant.

Table 5b.11 summarizes the size and age of northeast plants firing No. 6 oil as their primary fuel. Of these four of the plants, Oswego 5 and 6 and Martins Creek 3 and 4, are large and young. Whether it is more reasonable to provide for FGD on the stack side of the boiler or to fire lower sulfur oil is beyond the scope of this study. Indeed, it is not known whether FGD capability already exists at these plants nor is to known whether they already fire low sulfur oil.

In order to provide an estimate of cost and effectiveness for any study which might be conducted for these plants, a model plant of 850 MW aged 10 years will be used. Otherwise, it is clear that most plants are small and old. Accordingly, a model plant of 250 MW aged 25 years will be used. The difference is that the large young plant is eithr a base load plant or close to it, while the small, old plant is clearly a peaking plant.

5b.5.2.2 Generation of Electricity and Consumption of Oil

This section converts data prepared in previous sections to oil consumption data. Data on sulfur and SO_2 are also provided.

The 850 MW, 10 year oil plant, is assumed to run 7,000 hr/yr, for a load factor of 80 percent. The 250 MW, 25 year old plant, is assumed to run 1,500 hr/yr for a load factor of 17 percent. Both plants are assumed to have a heat rate of 10,564 Btu/KWh, which is the average of the heat rates reported for New York and Pennsylvania by Edison Electric Institute for 1982. (Although it seems reasonable to suppsoe that the older plant runs at a much higher heat rate, there were no readily available data to support this notion. Since the main purpose of this study is to compare the results of firing different sulfur content oils in the same boiler, rather than to compare two different boilers, this problem is not viewed as critical.)

Tables 5b.12 and 5b.13 contain information on oil consumption, fuel cost, sulfur input (content of fuel), SO_2 output, and the changes in these values relative to 3.8 percent sulfur fuel oil. Clearly, as sulfur content is reduced, fuel consumption, fuel cost, and sulfur and SO_2 values change. It remains to evaluate these changes in terms of kWh. this is the topic of the next section.

5b.5.2.3 Costs per Unit

In this section, the costs and changes in cost per unit of output and per unit of removal are presented. Three units have been used:

TABLE 5b.11 OIL-FIRED POWER PLANTS IN THE NORTHEAST

PLANT	UNIT	SIZE IN MW	AGE IN 1984
Port Jefferson	1	45.0	36
	2	46.0	34
	3	187.5	26
	4	187.5	24
Northport	1	387.1	17
	2	387.1	16
	3	387.1	12
	4	387.0	11
Albany	1	100.0	32
	2	100.0	32
	3	100.0	32
	4	100.0	30
Roseton	1	621.0	10
	2	621.0	10
fOswego	1	92.0	44
	2	92.0	43
	3	92.0	36
	4	100.0	33
	5	901.9	13
	6	901.9	4
Martins Creek	3	850.5	9
	4	850.5	7
Eddystone	3	321.0	10
	4	391.0	8
Cromby	1	187.5	30
	2	230.0	29

Source: Inventory of Power Plants in the United States,m 1981 Annual, DOE/EIA-0095(81)

TABLE 5b.12 OIL CONSUMPTION AND SULFUR INPUT/OUTPUT FOR 850 MW PLANT

S% by Weight	3.8%	1.6%	0.3%	0.1%
Oil Consumption, bbl/yr	9.84×10^6	10.06×10^6	10.22×10^6	10.20×10^6
Cost of Oil, %/bbl	28.00	28.50	34.36	36.38
Annual Fuel Bill, $/yr	275.5×10^6	286.7×10^6	351.2×10^6	371.1×10^6
Change in Annual Fuel Bill, $/yr*	n/a	11.2×10^6	75.7×10^6	95.6×10^6
Sulfur Input, tons/yr	62.5×10^3	26.3×10^3	4.9×10^3	1.6×10^3
Change in Sulfur Input, tons/yr*	n/a	-36.2×10^3	-57.6×10^3	-60.9×10^3
SO Output, tons/yr**	125.0×10^3	52.6×10^3	9.8×10^3	3.2×10^3
Chage in SO_2 Output, tons/yr*	n/a	-72.4×10^3	-115.2×10^3	121.8×10^3

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* All changes are with respect to 3.8 percent sulfur content

** It is assumed that each ton of S input results in 2 tons SO_2 output

TABLE 5b.13 OIL CONSUMPTION AND SULFUR INPUT/OUTPUT FOR 250 MW PLANT

S% by Weight	3.8%	1.6%	0.3%	0.1%
Oil Consumption, bbl/yr	620.1×10^6	634.3×10^6	643.9×10^6	642.7×10^6
Cost of Oil, %/bbl	28.00	28.50	34.36	36.38
Annual Fuel Bill, $/yr	17.4×10^6	18.1×10^6	22.1×10^6	23.4×10^6
Change in Annual Fuel Bill, $/yr*	n/a	0.7×10^6	4.7×10^6	6.0×10^6
Sulfur Input, tons/yr	3.9×10^3	1.7×10^3	308.7	102.2
Change in Sulfur Input, tons/yr*	n/a	-2.2×10^3	-3.6×10^3	-3.8×10^3
SO_2 Output, tons/yr**	7.8×10^3	3.4×10^3	617.4	204.4
Chage in SO_2 Output, tons/yr*	n/a	-4.4×10^3	-7.2×10^3	-7.6×10^3

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* All changes are with respect to 3.8 percent sulfur content

** It is assumed that each ton of S input results in 2 tons SO_2 output

- Fuel bill in mills/kWh
- Change in fuel bill
- Cost/ton of SO_2 removed

In all cases, only the average cost per kWh has been used as the unit of measure. Development of other figures, such as levelized figures, would have required, at least in the case of the young, 850 MW plant, consideration of changes in O&M expense due to use of lower viscosity oils. Also, the costs of cleaning storage tanks to prevent mixing oils (or, alternatively, the gradual reduction in sulfur content due to mixing) would have had to be considered. Nevertheless, the averages presented represent a fair analysis of cost impacts.

A note of caution seems appropriate at this point. Costs presented are for the model plants only. They do not represent impacts on the cost of service to ratepayers. In order to evaluate changes in electric rates, a complete analysis of changes in the rate base and revenue requirement and attendant changes in demand would be required. Such a study is beyond the present scope and would, in any event, require use of complex modeling.

Information for both plants is combined into a single table, Table 5b.14. This is possible because fuel use, and hence all measures tied to fuel use, has been scaled on annual kilowatt hours. The only difference between the plants is size. For reasons stated previously, factors such as different heat rates have not been taken into account. Levelizing, via the standard method, would not yield a difference eithr, due to the discounting of units of input and output at the same rate over the same time frame. (Levelizing would have generated some differences within plants but not between plants.)

As anticipated, the cost of SO2 reduction becomes increasingly expensive for larger reductions (diminishing returns). The switch from 3.8 percent to 1.65 fuel oil has a modest cost impact, 1.9 mils/kWh or $155/ton SO_2 removed. However, succeeding steps have much more serious impacts. Still, given the cost of FGD, the impacts appear relatively small.

TABLE 5b.14 COSTS PER UNIT FOR BOTH 850 AND 250 MW PLANTS

S% by Weight	3.8%	1.6%	0.3%	0.1%
Fuel Bill, mills/kWh	46.3	48.2	59.0	62.4
Change in Fuel Bill, mills/kWh	n/a	1.9	12.7	16.1
Cost of SO_2 Reduction, $/ton	n/a	154.7	657.1	784.9

5.b.6 Hydrodesulfurization

Hydrodesulfurization (HDS) is the process refineries use to clean fuel oils. The process involves contacting impure oil with hydrogen and catalysts to reduce the chemically bonded sulfur and nitrogen, metals and carbon residue content of the oil. The following paragraphs characterize the HDS process.

5.b.6.1 The General Process

Refineries initiate the typical hydrodesulfurization process by filtering atmospheric resid to remove rust, coke and other suspended material. The filtered atmospheric resid is then mixed with hydrogen, heated to 650° to 850° F and passed over one or more catalytic conversion beds. The most widely used catalysts are composites comprising cobalt oxide, molybdenum oxide and alumina, where alumina is the support carrying the other agents as promoters.

Numerous chemical reactions occur when the heated atmospheric resid and hydrogen contacts the catalyst. These reactions remove most of the oil's principal contaminant, sulfur, as H_2S. In the typical HDS process, hydrogen reacts with other species besides sulfur compounds, including nitrogen, nickel and vanadium. Nitrogen components break down to liberate ammonia from the oil. This is called denitrogenation or denitrification. Nickel and vanadium, bound as organo-metal compounds in the oil, are liberated by reaction with the hydrogen. Most of the liberated metals deposit (as the sulfide) on the catalyst surface or in its pores and slowly deactivate the catalyst. Other reactions associated with hydrodesulfurization break up large complex molecules such as asphaltenes and reduce the carbon residue of the product oil.

The use of catalysts in the HDS process enables the reactions with hydrogen to occur under moderate reaction conditions. Without the catalysts, higher reaction temperatures or pressures are required. This leads to greatly increased hydrogen consumption due to hydrogenation of aromatic ring systems which are abundant in high boiling petroleum fractions.

Many companies are engaged in developing and using hydrodesulfurization processes. these processes are similar in basic concept and vary only with regard to catalysts, process conditions, and complexity. Gulf Oil Company, for example, has developed three HDS processes known as Gulf II, III and IV> Gulf II, the simplest commercial version marketed by Gulf, comprises the following basic elements: feed filter, heater, single-stage catalytic reactor, gas/liquid separator, fractionating column and gas treatment section. This simple process system is capable of producing fuel oil and approximately 1 percent sulfur from a feedstock such as atmospheric resid containing 2 to 4 percent sulfur. To produce a lower sulfur content product, additional catalytic reaction stages must be included in the process. Gulf III system has two catalytic reaction stages and produces fuel of approximately 0.3

percent sulfur content from atmospheric resid containing 2 to 4percent sulfur. Gulf IV the most advanced Gulf HDS process, uses three catalytic reactors and produces fuel oils of approximately 0.1 percent sulfur.

5b.6.2 Specific Process Characteristics

Table 5b.15 illustrates the typical product properties obtained when the three versions of the Gulf process are applied to Kuwait atmospheric resid containing 3.8 percent sulfur. This table indicates that the number of catalyst stages strongly affects both physical and chemical properties of the product oil. In addition to greater sulfur removal, an increase in catalyst stages means a reduction in pour point, viscosity and chemical impurities such as nitrogen, metals, salts, and ash.

While the benefits derived from increased catalyst stages are significant, there are associated costs. First, the amount of hydrogen consumed increases with the degree of desulfurization. Second, catalyst cost increases. Third, heating value per gallon is reduced slightly. To explain, even though heating value/pound increases with the degree of desulfurization, the density of the product decreases. As a result, slightly greater volumes of cleaned fuel oil must be burned to produce the same amount of heat provided by an untreated residual oil. The change in heating value is of the order of 1 to 3 percent on atmospheric resids and about 55 on vacuum resids. However, when the degree of clean up is considered, this energy impact seem insignificant.

The composition of the feedstock to the HDS process strongly influences the amount of hydrogen and catalyst consumed in the process. W.L. Nelson has correlated hydrogen consumption with sulfur reduction for a variety of resid feeds. His work shows that to obtain 90 percent reduction in sulfur for an 18° API feedstock, about 650 scf of hydrogen are consumed per barrel of oil processed; whereas a 4° API feed requires 1200 scf/barrel. Nelson also correlated hydrogen consumption by resid type with sulfur desired in the fuel oil product. He found that 345 to 775 scf of hydrogen are required to produce 0.3 to 1.0 percent sulfur fuel oils from atmospheric resid and 870 to 1150 scf are required to get the same results from vacuum resid.

The metals content of the feedstock impacts the catalyst consumed in the HDS process. During the process, metals are deposited onto the catalyst surface or in the pores. this leads to deactivation of the catalyst, a condition only overcome by a temperature or pressure increase to maintain acceptable processing rates. The increase in required severity of process conditions leads to more hydrocracking with a subsequent increase in hydrogen consumption.

A further complication related to the metals content of the feed is a shortening of catalyst life. Even though some deactivation can be tolerated, the resulting increase in hydrogen uptake mans the catalyst must be changed out

TABLE 5b.15 TYPICAL PROPERTIES OF LSFO PRODUCT FROM GULF HDS PROCESSES

	Untreated	Gulf II	Gulf III	Gulf IV
Product Yield: Vol. %	--	89.4	97.5	97.1
Product Properties:				
Cut Point: °F	650	650	375	375
Gravity: °API	16.6	20.0	23.4	24.1
Sulfur: Wt. %	3.8	1.0	0.3	0.1
Carbon Residue: Wt. %	9.0	5.31	3.33	2.75
Nitrogen: Wt. %	0.22	0.13	0.13	0.09
Nickel: ppm	15.0	4.6	1.3	0.4
Vanadium: ppm	45.0	8.2	2.2	1.0
Viscosity: SUV (210°F)	250	107.3	52	45
Ash: Wt. %	0.02	0.004	0.003	0.003
Slat: ppm*	44.9	0	0	0
Heat of Combustion: Btu/lb	**	19,110	19,250	19,375
Hydrogen: Wt.%	**	12.1	12.5	12.7
Carbon: Wt. %	**	86.7	87.1	87.1
Pour Point: °F	**	+60	+35	0
Hydrogen Consumption: SCF/bbl	--	497	663	812

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* Salt refers to all water-soluble cations, determined as halide and reported as NaC1 before desalting

** Not stated

sooner. Nelson studied the effect of metals on catalyst consumption and showed that: 1) for 90 percent sulfur removal from a 25 ppm metals content feedstock, about 27 barrels of oil can be processed per pound of catalyst; 2) to achieve the same sulfur performance with a 100 ppm metals content feedstock, only 4.5 barrels can be processed per pound of catalyst; and 3) a 300 ppm feedstock requires almost 1 pound of catalyst per barrel. Clearly, high metal feedstocks are a costly problem to the refiner. Most refiners are using a separate stage of lower cost catalyst material prior to using the special hydrodesulfurization catalysts. these separate stages many be packed with a material (e.g., alumina or clay) that collects the metals and "guards" the subsequent high activity catalyst. Exxon uses such a process and calls it RESIDfining.

The preceding paragraphs suggest that catalyst life varies. Most refiners use fixed catalyst beds. these beds require a process shutdown when catalysts are replaced. Depending on product requirement and feedstock composition, the catalysts in a fixed bed system are usually changed once or twice per year. For example, a six-month catalyst life is the design base for the Gulf IV system producing 0.1 percent low sulfur fuel oil from 3.85 sulfur Kuwait Resid (97 percent HDS). Similarly, a 400 to 500 day catalyst life can be achieved when using Arabian Heavy with RESIDfining at 75 percent HDS.

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6. THE DISPATCHING MODULE

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6.1 Introduction

Dispatching is the process of allocating a given demand for electric energy among generating units designated to meet that demand. Two quantities are of primary importance in making the allocation. The first quantity is the net operating cost of the generators. The second is the net contributions the generators make to various emission categories -- typically, sulfur dioxide, oxides of nitrogen and total suspended particulates.

The purpose of the dispatching module is to find the allocation that minimizes a selected quantity of concern while meeting constraints on the other quantities of concern and keeping within the operating ranges of the generators. Typically, the dispatching module will be used to find the least-cost solution while maintaining regional limits on SO_2, NO_x and TSP. However it could also be used in other modes. For example, SO_2 could be minimized while limits on cost, NO_x and TSP are maintained. Another example would be to find the Pareto optimal (best possible) tradeoffs between cost and SO_2 while maintaining constraints on NO_x and TSP.

In the remainder of Section 6.1, we discuss some general methodological issues. In Section 6.2 we discuss two dispatching modules that have been developed and tested. They are a merit-order module and a linear programming module. The former is smaller and simpler; it was developed as an interim measure to serve while the latter was being written. The linear programming module is much more powerful and capable. This module should be used in preference to the merit-order module unless dispatching will have little influence on the case being studied and the program user's wishes to save the time and storage that the linear programming module requires. Section 6.3 presents some stand-alone results from the linear programing module. Section 6.4 contains a summary.

6.1.1 Regions and Periods

The modeling approach used by the Advanced Utility Simulation Model (AUSM) relies on breaking space and time into discrete units. The smallest spatial unit used in dispatching is called a region. Usually it corresponds to a state, but occasionally it may be larger or smaller. The fundamental temporal unit used is called a period. In examining events in the immediate future, the periods used are usually comparatively short--on the order of a year in length. However, to examine events in the distant future we may use longer periods--5 to 10 years, for example.

6.1.2 Generators, Plants, and Units

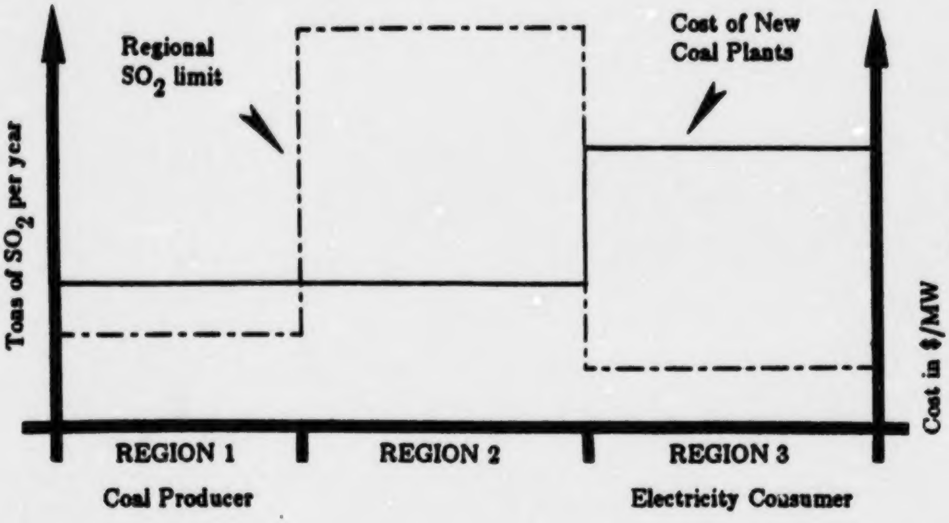
The entities that can be dispatched may be individual generating units, plants (containing several units), or aggregations of plants (for instance, the set of all old, small, coal-fired plants in a state). In the remainder of this chapter all such entities are referred to as generators.

The dispatching module can work with arbitrary mixes of generators--some of them can represent individual units, others plants, and still others aggregations of plants. In the state-level AUSM, the generators are usually units or plants but in the national-level dispatching procedures, the generators will usually be aggregations of plants.

6.1.3 Methodological Perspectives

To cover policy impacts adequately, electric utility activity must be examined in three contexts, or perspectives. The first context is over extended time horizons, 20 years or more into the future, and extended geographical areas, encompassing many states. This perspective is called multiple region-multiple period (MRMP). The MRMP perspective is necessary for examining macro-level, interregional activities such as remote plant siting (see Figure 6-1) and interregional exchanges of energy. Although this perspective will not provide a detailed picture, it is quite important. Consider, for instance, interregional energy exchanges. From the point of view of many impacts, they are equivalent to a change in regional demand. Therefore, many of the benefits of having a sophisticated model for predicting demand will be lost if we cannot predict interregional energy exchanges with about the same accuracy.

Figure 6-1
REMOTE PLANT SITING CASE


Regional
SO_2 limit
Cost of New
Coal Plants
Tons of SO_2 per year
Cost in $/MW
REGION 1
REGION 2
REGION 3
Coal Producer
Electricity Consumer

Note: In the simplified scenario shown here, coal is produced in Region 1 for conversion to electric energy that will be consumed in Region 3. If the delivery costs of coal and electric energy are comparable, then Region 2 would seem to be the best location for the generating plant to convert the coal to electricity. With more realistic scenarios the best regions and periods in which to locate new plants will not be as obvious.

The second context is over extended time horizons but for only a single region. It is called the single region-multiple period (SRMP) perspective. This context is necessary for examining long-term activities that are specific to a region—for example, the planning of new generating facilities in a state over an extended horizon. The picture from this perspective, of course, will not be as broad as from the MRMP perspective, but the detail will be finer.

The third context, the single region-single period (SRSP) perspective, which is used in the state-level AUSM, extends over only one period and one region. This perspective is necessary to obtain the detailed picture required by recursive portions of the model. However, the SRSP perspective is too narrow to capture many interregional and interperiod activities.

Dispatching decisions affect operating cost and emissions, which affect the views from all three perspectives.

The state-level version of the AUSM operates in the SRSP context by considering one state at a time and by recursively moving from one period to another but never considering all the periods simultaneously.

Developments in the MRMP context will lead to a national-level version of the AUSM. Models in the SRMP context will be needed to provide a path by which macro-level information generated with the national model can be supplied to the state-level model.

6.1.4 Methodological Requirements

A reasonable set of requirements for a dispatching methodology or mix of methodologies consists of the following:

1. *Contextual Compatibility.* The methodology must apply to all three contexts and must produce consistent results in moving from one to another. (For instance, the methodology would be inconsistent if it indicated emissions decreasing with time in the MRMP context but increasing with time in all the SRMP contexts.)

2. *Procedural Compatibility.* The methodology must mesh with the methodologies used in the other parts of the AUSM, particularly in terms of fidelity, data requirements, and data production.

3. *Systematic Constraint Handling.* The methodology must be capable of accommodating large numbers of constraints on quantities such as regional emissions and fuel availability.

4. *Flexibility.* With all large models there is a continual need for revisions. In the case of the AUSM, this means being able to add new constraints and decision variables as well as being able to delete old constraints and variables. In addition, it may eventually be necessary to include some systematic way of handling the uncertainties in long-term predictions.

5. *Computational Feasibility.* Very expensive methods are undesirable.

6. *Sensitivity Production.* It is expected that users of the AUSM will find information on the sensitivity of solutions to parameter variations at least as valuable as the solutions themselves.

6.1.5 Candidate Methodologies

The ways in which dispatching decisions are made can be grouped into five categories: (1) heuristics and "greedy" algorithms,[1] (2) linear programming, (3) quadratic programming, (4) nonlinear programming, and (5) probabilistic methods that can be appended to the other categories to handle random generator outages. All of these, except linear programming, have disadvantages serious enough to disqualify them. Specifically, heuristics and greedy algorithms can be disqualified for their inability to systematically handle the large numbers of constraints that are contained in virtually all policy analysis scenarios. Nonlinear programming [1,2] and probabilistic methods can be disqualified for reasons of computational infeasibility and procedural incompatibility. Quadratic programming can be made computationally feasible but only at the expense of its ability to handle large numbers of constraints [3]. This leaves linear programming. It meets requirements 2 through 6 (listed in Section 6.1.3). In all probability, it will also meet requirement 1. However, this cannot be demonstrated until the SRMP and MRMP models are available for tests.

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[1] A greedy algorithm grabs the first promising solution it comes upon. This solution is seldom optimal. Merit ordering is a good example of a greedy algorithm.

6.1.6 Status

The development, coding, and testing of a dispatching module based on linear programming have been completed. The module has been integrated into the state-level version of the AUSM (i.e., the version that works in the SRSP context by moving recursively from one period to another, but never considering all the periods simultaneously). For the SRMP and MRMP contexts we are in the process of developing linear programming approaches that will simultaneously consider dispatching, pollution control, and planning in the new EPOS module (see Chapter 8). The dispatching methodology will remain essentially the same in all three contexts so that we can reuse much of the code from the module that has been completed.

In addition to the linear programming module, we have completed two other dispatching modules. The first uses a merit order for dispatching; the second, a special form of quadratic programming.

Merit-order dispatching is a greedy strategy that has been used in other models, such as the Utility Simulation Model [4]. We coded it as an interim tool to serve while the linear programming module was being written and debugged; it is described briefly in Section 6.2.1.

Work on a quadratic programming approach was undertaken with the full knowledge that it was a high-risk venture. There was a small chance that we could use certain special structures of power system problems to improve on the efficiency of generalized quadratic programs. We were able to develop an interesting methodology that may have real time control applications. However, after a moderate investment of time, we had not found a methodology that would fit in the AUSM. Therefore, further work on quadratic programming was abandoned. An account of this effort appears in Reference 3.

6.2 Analytical Structure

6.2.1 Dispatching by Merit Order

As noted in Section 6.1.5, a merit-order dispatching methodology was developed as an interim measure before implementation of the linear programming methodology. The purpose of the merit-order dispatching is to allocate generation at minimum cost to meet demand without violating any availability or capacity factor constraints. The merit-order dispatching cannot handle regional emission constraints.

The generators are arranged in ascending order of their operating and maintenance (O&M) costs (in dollars per megawatt hour). The cheapest generator is assigned to take as much load as its rating, availability, and capacity factor allow. Then the next cheapest generator is deployed, and so on (see Figure 6-2).

6.2.2 Dispatching by Linear Programming

6.2.2.1 **Assumptions.** Seven important assumptions are made in the linear programming analysis:

1. The load duration curve can be approximated by discrete steps (see Figure 6-3).[2] In support of this assumption, we note that little information is available on the shape of the load duration curve and that use of a stepped approximation, even if the number of steps is small, does not compromise the fidelity of the input data.

2. Delivery losses can be summed and added to the demand. The transmission and distribution networks are not included in the model. In essence, this means that all the generators in the region are lumped at a single node with the net load. (This assumption will be relaxed in the MRMP context.)

3. Either the amount or the unit costs of interregional energy exchanges is known. If the amount is known, it is included in the net load duration curve. If the cost is known, then interregional transfers are modeled by a fictitious generator. (A fictitious generator exists only in the model. The O&M costs are set equal to the costs of purchased power. Its capacity is the amount of purchasable power.)

4. If energy shortfalls are to be allowed, their costs (in dollars per megawatt hour) are known.

5. Forced outages can be modeled by the derating procedure.

6. For dispatching in the SRSP context, the fuel to be used by each generator is known. (In the SRMP and MRMP contexts, the dispatching procedure will make fuel selections, but in the SRSP context these selections are made by the pollution control module.)

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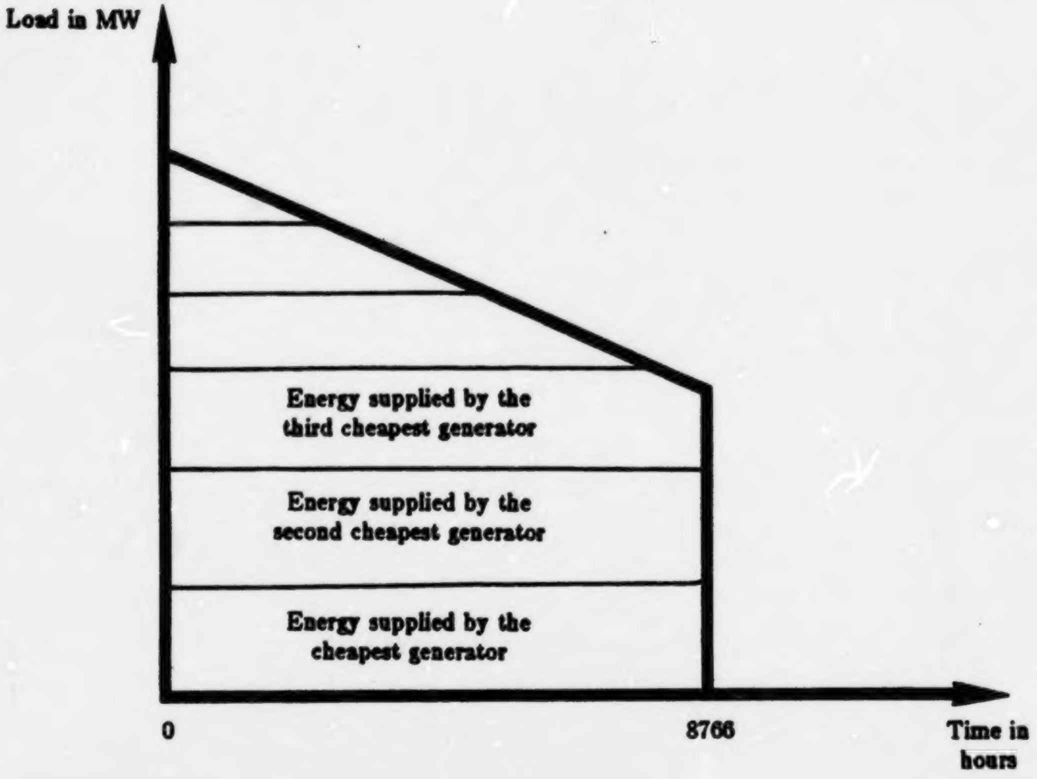
[2] Although Figure 6-3 shows a three-step approximation, the present version of the program is dimensioned to allow up to a five-step load duration curve. If necessary, the dimensions can be increased.

Figure 6-2
ALLOCATION OF GENERATORS TO MEET THE LOAD DURATION CURVE



Note: This figure shows a ramp approximation to the load duration curve and the arrangement of the generators, in ascending order of their O&M costs, to meet the load. If, after all the generators have been deployed, there is still some unserved load, this load is met by purchasing energy from out-of-state sources at prices that must be given to the procedure.

7. The cost of producing a megawatt hour of electric energy from a generator is constant and known. The amounts of the various emissions produced per megawatt hour are constants for each generator and are known.

6.2.2.2 Nomenclature. The nomenclature used in the linear program for the dispatching module is explained in Table 6-1.

6.2.2.3 Least-Cost Dispatching with Emission Constraints. In the single region/single period context, the problem is to find the least-cost dispatching strategy, given:

1. The length of the period to be considered

2. The peak and average values of the net demand for power over the period (net demand is the sum of the end-use demand, the delivery losses, and the scheduled exports)

3. Characteristics of the generating plants available for dispatching to meet the demand (see Plant Data in Table 6-1)

4. The amount and average cost of energy available, if needed, from outside the region under consideration

5. The limits to be enforced on the total SO_2, NO_x, and TSP produced in the region.

This translates into the following linear programming problem:

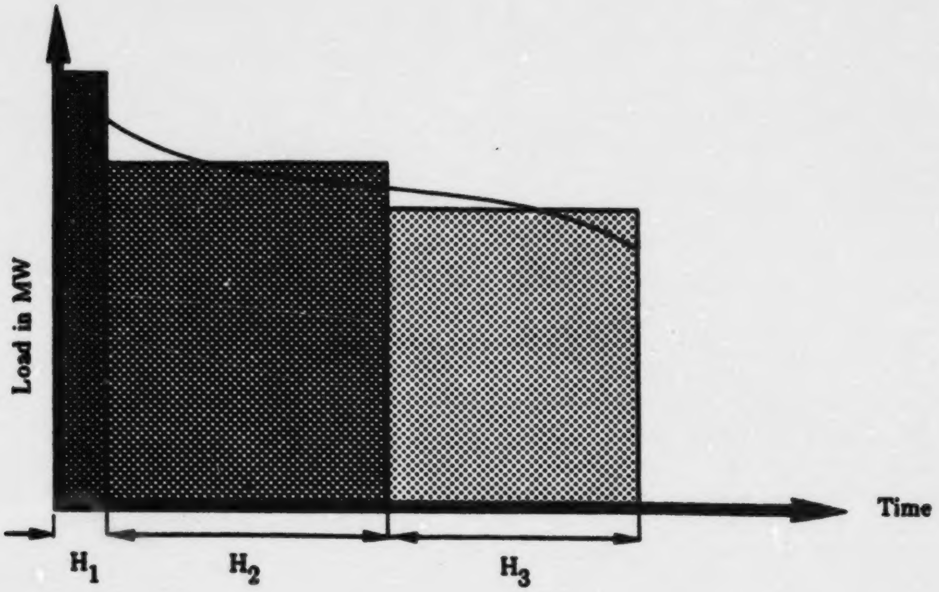
$$\underset{P_{nj}}{\mathit{Minimize}} \sum_{j=1}^{J} \sum_{n=1}^{N} C_n P_{nj} H_j; \quad \mathit{Cost}$$

Subject to:

1. The demand constraint,

$$\sum_{n=1}^{N} P_{nj} = P_j \ \forall j \in J;$$

Figure 6-3
THREE-STEP APPROXIMATION OF THE LOAD DURATION CURVE



Note: The present version of the program allows up to a five-step approximation. The dimensions can be increased if necessary.

Table 6-1
DISPATCHING MODULE NOMENCLATURE

Symbol	Explanation	Type
Load Data		
J	Number of divisions of the load duration curve (see Figure 6-3)	Input
P_j	Load in MW of the jth division of the load duration curve (see Figure 6-3)	Input
H_j	Duration in hours of the jth division of the load duration curve (see Figure 6-3)	Input
Plant Data		
N	Number of generators to be dispatched	Input
$\overline{N}$	Subset of generators, 23 largest units in terms of $(AV_n - \overline{CF})_n\ P_n$	Internal
$\overline{P}_n$	Maximum capacity of the nth generator (MW)	Input
AV_n	Availability factor of the nth generator $(0 \leq AV_n \leq 1)$	Input
$\overline{CF}_n$	Maximum capacity factor of the nth generator $(0 \leq CF_n \leq 1)$	Input
C_n	Operating cost of the nth generator (dollars per MWh)	Input
K	Number of emissions to be considered	Input
e_{nk}	Emission coefficient of the nth generator for the kth emission in tons per MWh (tons of emission type k emitted by the nth plant per MWh)	Input
P_{nj}	Generation in MW of the nth generator in the jth division of the load duration curve	Output
E_n	Total energy in MWh produced by the nth generator	Output
Regional Data		
$\overline{E}_k$	Upper limit (cap) in tons of the kth emission for the region	Input

2. Regional emission constraints,

$$\sum_{n=1}^{N} e_{nk} \sum_{j=1}^{J} H_j P_{nj} \leq \bar{E}_k \; \forall \; k \epsilon K;$$

3. Capacity factor constraints,

$$\sum_{j=1}^{J} H_j P_{nj} \leq \overline{CF}_n \; (\bar{P}_n \sum_{j=1}^{J} H_j) \quad \forall \; n \epsilon N$$

4. Availability constraints,

$$O \leq P_{nj} \leq AV_n \bar{P}_n \; \forall \; n \epsilon \bar{N} \text{ and } j \epsilon J$$

$$O \leq P_{nj} \leq \overline{AV}_{nj} \bar{P}_n \; \forall \; n \epsilon \bar{N}, N \epsilon N \text{ and } j \epsilon J$$

The availability constraints are of the single upper bound (sub) type and are easier to handle than more general constraints.

This formulation has the following gross features. First, the total number of variables = N * J. The numbers of different types of constraints are as follows:

Type of Constraint	*Number*
Demand	J
Regional emissions	K
Capacity factor	$\bar{N}$
Availability	J*N
Total	J+K+$\bar{N}$+N·J

The code allows for N ≤ 400, J ≤ 5, and K ≤ 3. These dimensions can be increased if necessary.

Note that only a subset of the units have explicit capacity factor constraints. The remaining units instead use upper bounds on the operating variables. In general, the $\overline{AV}_{nj}$ in the bounds are chosen to be the availability for the peak segments, and proportional to the P_j values for the off-peak segments so that the capacity factor constraint would be met if the unit were operated at the upper bounds. For a three-segment load duration curve, the $\overline{AV}_{nj}$ values would be

$$\overline{AV}_{n1} = AV_n \quad \text{if} AV_n H_1 \leq \overline{CF}_n \sum_{j=1}^{J} H_j$$

$$\text{otherwise } \overline{AV}_{n1} = \overline{CF} \sum_{j=1}^{J} H_j / AVn$$

$$\text{and } \overline{AV}_{n2} = \overline{AV}_{n3} = 0$$

$\overline{AV}_{n2}$ and $\overline{AV}_{n3}$ chosen to satisfy

$$H_1\overline{AV}_{n1} + H_2\overline{AV}_{n2} + H_3\overline{AV}_{n3} = \overline{CF}_n \sum_{j=1}^{J} H_j$$

If $\overline{AV}_{n2}$ resulting from requiring $\overline{AV}_{n2}/P = \overline{AV}_{n3}/P_3$ is less than or equal to AV_n, then use those values.

Otherwise, set $\overline{AV}_{n2} = \overline{AV}_n$ and choose $\overline{AV}_{n3}$ to satisfy the summation constraint.

This procedure is done to lower the number of capacity factor constraints while generally yielding an equivalent solution to the problem where $N = \overline{N}$. The savings that results is faster solution procedure and the ability to handle an increased number of generating units.

The formulation remains the same for the SRMP and MRMP contexts, except that the decision variables are augmented to include fuel selections and the constraints are augmented to include all applicable limits on fuel availability. While this is not a major step, it does require slightly different nomenclature. Further details will be provided in a forthcoming report on the national version of the AUSM [5].

6.2.2.4 **Least-Emission Dispatching**. For cases where we wish to minimize the net production of an emission (say the mth emission) while maintaining constraints on the remaining emissions and cost, the formulation is changed to the following:

$$\underset{P_{nj}}{Minimize} \sum_{n=1}^{N} e_{nm} \sum_{j=1}^{J} H_j P_{nj} : \quad \text{Regional production of the mth emission}$$

Subject to:

1. **The demand constraint,**

$$\sum_{n=1}^{N} P_{nj} = P_j \;\; \forall \; j \epsilon J;$$

2. **Regional constraints on the emissions not being minimized,**

$$\sum_{n=1}^{N} e_{nk} \sum_{j=1}^{J} H_j P_{nj} \leq \bar{E}_k \;\; \forall \; k \epsilon Km;$$

3. **Capacity factor constaints,**

$$\sum_{j=1}^{J} H_j P_{nj} \leq \overline{CF}_n (\bar{P}_n \sum_{j=1}^{J} H_j) \; \forall \, n \epsilon N$$

4. **Availability constraints,**

$$O \leq P_{nj} \leq AV_n \bar{P}_n \; \forall \, n \epsilon \bar{N} \text{ and } j \epsilon J$$

$$O \leq P_{nj} \leq \overline{AV}_{nj} \bar{P}_n \; \forall \, n \epsilon \bar{N} N \epsilon N \text{ and } j \epsilon J$$

5. **A cost constraint,**

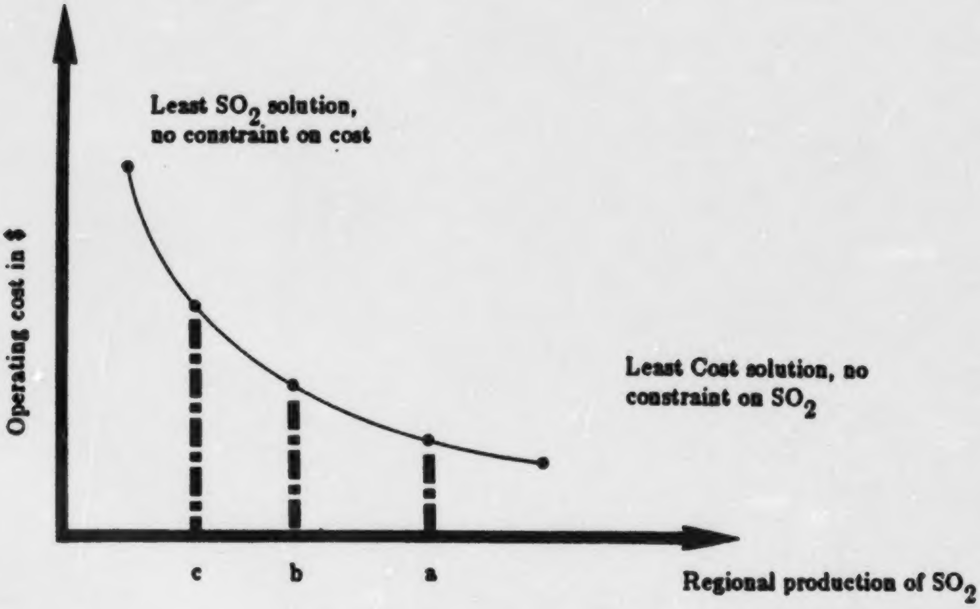
$$\sum_{j=1}^{J} \sum_{n=1}^{N} C_n P_{nj} H_j \leq \bar{C}$$

where $\bar{C}$ is the upper limit on operating costs.

6.2.2.4 Pareto Optimal Frontiers. In some cases, it is useful to determine the best possible tradeoffs between two of the quantities of concern, for example, cost and SO_2. As shown in Figure 6-4, the curve, or Pareto frontier, representing these tradeoffs can be generated. First, the extreme points are found by solving the least-cost and the least-SO_2 problems. Then intermediate points are generated by solving the least-cost problem with the SO_2 limit set to a, then b, then c, and so on.

6.2.2.5 Choice of a Linear Programming Package. To solve the linear programming problems, the dispatching module uses a package called XMP [6], which is in the public domain. Originally, a package called LINDO was used. However, LINDO is proprietary and slower than XMP. In chosing XMP, we examined a fairly large number of packages; XMP seems to be the best by far. It can quite easily accommodate 2500 variables, 1000 regular constraints, and 2500 sub constraints.

Figure 6-4
TRADEOFF BETWEEN COST AND SULFUR DIOXIDE EMISSIONS



Note: To find the curve of the best possible tradeoffs between cost and SO_2, first find the extreme points by solving the least cost and the least SO_2 problems. Then generate intermediate points by solving the least-cost problem with the SO_2 limit set to a, then b, and so on.

6.3 Sample Stand-Alone Module Results

The data generated by the dispatching module can be divided into three categories: (1) regional totals, including the total operating cost and the total amounts of the three types of pollutants, (2) generator-specific information, including the operating cost, the energy produced, and the pollutants produced by each generator, and (3) various sensitivities and tradeoffs.

As an illustration, consider a region with a peak demand of 31,000 megawatts and an energy requirement of 175,000 gigowatt hours. The region has 60 generators with a total capacity of 39,000 megawatts.

Tables 6-2 and 6-3 show some of the results for a case in which no limitations on emissions are assumed, neither regional nor generator specific. Figure 6-5 shows the effects on operating cost of various regional limits on SO_2 production. By moving leftward across the figure from the least-cost solution, a very large decrease in SO_2 can be obtained for a small increase in cost.

Table 6-2
REGIONAL TOTALS: NO REGIONAL EMISSION CONSTRAINTS

Generator Type	Operating Cost (millions of dollars/year)	SO2 Emissions (tons/year)
Coal	$ 343	23,022
Nuclear	1781	
Distillate oil	288	
Residual oil	113	
Natural gas	0	
Other (including unscheduled purchases)	245	
Other Contributors to Operating Costs		
Miscellaneous O&M	825	
Pollution control	564	
Transmission and distribution	1225	
Total operating cost for the year:	$5384 * 10^6	

Table 6-3
GENERATOR-SPECIFIC INFORMATION: NO REGIONAL EMISSION CONSTRAINTS

	Inputs				Outputs		
Generator Number	Capacity (MW)	Availability	Fuel Type[a]	Heat Rate (Btu/KWh)	Operating Cost ($/MWh)	Energy Produced (GWh)	Capacity Factor
1.0	129.0	0.90	1	10999.0	24.5	763.3	0.67
2.0	375.0	0.90	1	11091.0	25.5	2218.9	0.68
3.0	150.0	0.80	1	12000.0	29.1	263.0	0.20
4.0	900.0	0.95	1	15000.0	32.3	1873.7	0.24
5.0	900.0	0.90	2	11500.0	63.2	0.0	0.00
6.0	540.0	0.85	2	8798.0	49.1	1005.9	0.21
7.0	900.0	0.70	3	9500.0	58.6	0.0	0.00
8.0	200.0	0.78	3	10000.0	63.8	0.0	0.00
9.0	675.0	0.90	3	12000.0	53.7	1331.3	0.22
10.0	450.0	0.90	3	12000.0	53.7	887.6	0.22
11.0	500.0	0.60	4	14500.0	77.1	0.0	0.00
12.0	700.0	0.60	4	14500.0	77.1	0.0	0.00
13.0	960.0	0.80	6	13000.0	21.5	5049.2	0.60
14.0	1200.0	0.80	6	13500.0	28.8	2103.8	0.20
15.0	2000.0	0.80	6	11000.0	20.4	14025.6	0.80
16.0	100.0	0.90	7	20000.0	49.0	197.2	0.23
17.0	1250.0	0.75	0	18000.0	63.0	0.0	0.00
18.0	2500.0	0.80	0	15000.0	57.3	976.8	0.04
19.0	1000.0	0.80	5	14000.0	81.0	0.0	0.00
20.0	4000.0	0.80	6	11000.0	18.0	26298.0	0.75
21.0	129.0	0.90	1	10999.0	24.5	763.3	0.67
22.0	375.0	0.90	1	11091.0	25.5	2218.9	0.68
23.0	150.0	0.80	1	12000.0	29.0	263.0	0.20
24.0	900.0	0.95	1	15000.0	32.3	1873.7	0.24
25.0	900.0	0.90	2	11500.0	63.2	0.0	0.00
26.0	540.0	0.85	2	8798.0	49.1	1005.9	0.21
27.0	900.0	0.70	3	9500.0	58.6	0.0	0.00
28.0	250.0	0.78	3	10000.0	63.8	0.0	0.00
29.0	675.0	0.90	3	12000.0	53.7	1331.3	0.22
30.0	450.0	0.90	3	12000.0	53.7	887.6	0.22
31.0	500.0	0.60	4	14500.0	77.1	0.0	0.00
32.0	700.0	0.60	4	14500.0	77.1	0.0	0.00
33.0	990.0	0.80	6	13000.0	21.5	5049.2	0.60
34.0	1200.0	0.80	6	13500.0	28.8	6311.5	0.60
35.0	2000.0	0.80	6	11000.0	20.4	10797.5	0.62
36.0	100.0	0.90	7	20000.0	49.0	197.2	0.23
37.0	1200.0	0.75	0	18000.0	63.0	0.0	0.00
38.0	2500.0	0.80	0	15000.0	57.3	4383.0	0.20
39.0	1000.0	0.80	5	14000.0	81.0	0.0	0.00
40.0	4000.0	0.80	6	11000.0	18.0	26298.0	0.75
41.0	129.0	0.90	1	10999.0	24.5	763.3	0.67
42.0	375.0	0.90	1	11091.0	25.5	2218.9	0.68

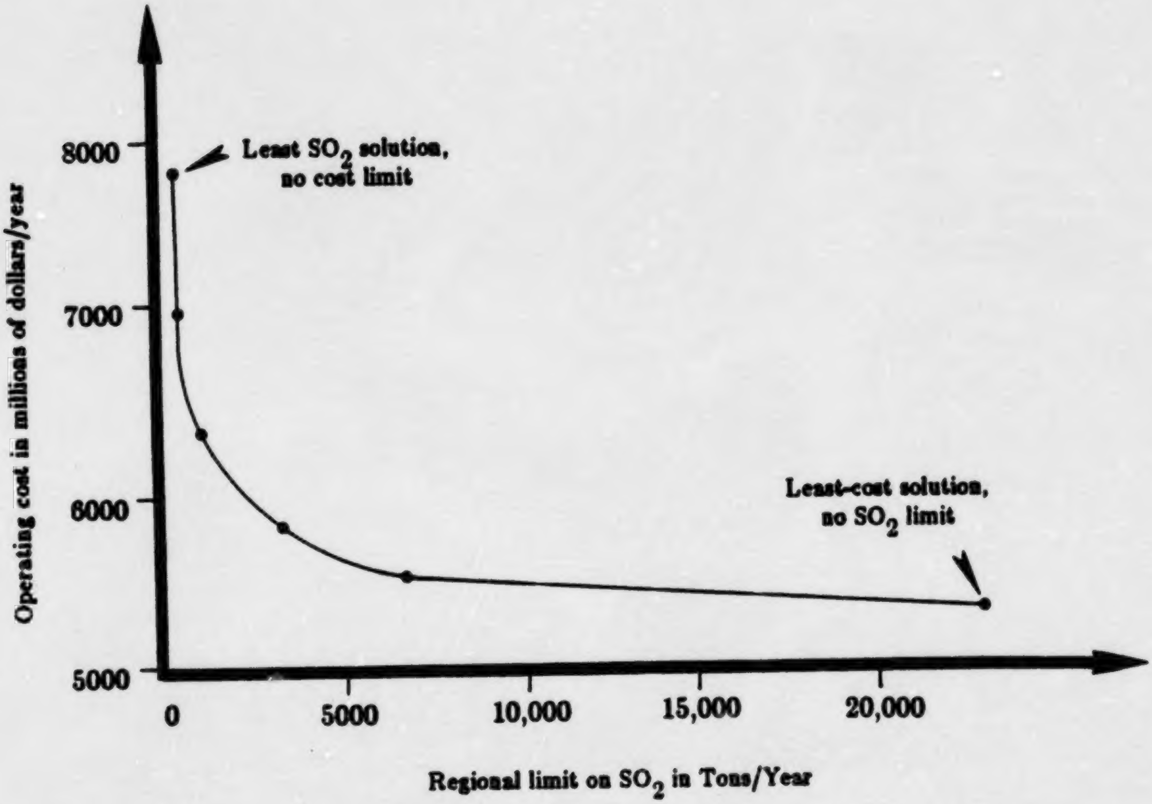
Table 6-3 (contd.)

		Inputs				Outputs	
Generator Number	Capacity (MW)	Availability	Fuel Type[a]	Heat Rate (Btu/KWh)	Operating Cost ($/MWh)	Energy Produced (GWh)	Capacity Factor
43.0	150.0	0.80	1	12000.0	29.1	263.0	0.20
44.0	900.0	0.95	1	15000.0	32.3	1873.7	0.24
45.0	900.0	0.90	2	11500.0	63.2	0.0	0.00
46.0	540.0	0.85	2	8798.0	49.1	1005.9	0.21
47.0	900.0	0.70	3	9500.0	58.6	0.0	0.00
48.0	200.0	0.78	3	10000.0	63.8	0.0	0.00
49.0	675.0	0.90	3	12000.0	53.7	1331.3	0.22
50.0	450.0	0.90	3	12000.0	53.7	887.6	0.22
51.0	500.0	0.60	4	14500.0	77.1	0.0	0.00
52.0	700.0	0.60	4	14500.0	77.1	0.0	0.00
53.0	960.0	0.80	6	13000.0	21.5	5049.2	0.60
54.0	1200.0	0.80	6	13500.0	28.8	6218.1	0.59
55.0	2000.0	0.80	6	11000.0	20.4	10519.2	0.60
56.0	100.0	0.90	7	20000.0	49.0	197.2	0.23
57.0	1250.0	0.75	0	18000.0	63.0	0.0	0.00
58.0	2500.0	0.80	0	15000.0	57.3	0.0	0.00
59.0	1000.0	0.80	5	14000.0	81.0	0.0	0.00
60.0	4000.0	0.80	6	11000.0	18.0	26298.0	0.75

[a] 1= coal; 2 = residual oil; 3 = distillate oil; 4 = gas; 6 = nuclear; 0, 5, 7 = other.

Figure 6-5

EFFECTS OF VARIOUS REGIONAL SOLUTIONS ON SULFUR DIOXIDE PRODUCTION



Note: This figure shows the effects that the regional limit on SO_2 has on operating cost. Notice that by moving leftwards from the least-cost solution, a very large decrease in SO_2 can be obtained for a small increase in cost. Such situations are not atypical and can be important in policy studies.

6.4 Summary and Conclusions

The AUSM dispatching module can dispatch units on the basis of either least cost or least emissions; it can also be used to find the tradeoffs among cost and emissions. In all three modes of usage, regional limits can be placed on cost and various types of emissions.

As discussed above, the module uses linear programming. The advantages that result are:

1. Large numbers of constraints can be accommodated and new constraints, should the need for them become apparent (as it invariably will), can be added easily.

2. In the complex decision-making environments that are inherent in the phenomena covered by the AUSM, the module can make better decisions than can simpler heuristics and greedy algorithms.

3. More elaborate procedures, such as nonlinear programming, would be computationally infeasible. Besides, the fidelity of the input data is not high enough to warrant their use.

4. The methodology is upwardly mobile so that it can be used for the national-level model.

5. Both analytical and prescriptive measures for handling uncertainty can be added to the methodology without undue strain.

The main disadvantages that result from the use of linear programming are:

1. Computational intensity (in comparison with most greedy algorithms).

2. The well-known tendency of linear programming to sometimes produce drastic changes in the solution in response to small changes in the problem.

On balance, the advantages far outweigh the disadvantages.

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7. THE CAPACITY PLANNING MODULE

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7.1 Introduction

Development of the capacity planning module for the Advanced Utility Simulation Model began with a review of the planning and siting module developed by Teknekron Research, Inc. (TRI) in 1979 for the Utility Simulation Model (USM) [1]. The USM was the only model that dealt with individual generating units at a level of detail compatible with AUSM design requirements. From a structural viewpoint, it became apparent immediately that retention of the USM county-level power plant siting algorithm in the planning module would create costly logistical problems in the annually recursive framework adopted for the AUSM. It was decided to split county-level siting into a separate module and to deal only with state totals in the planning module itself.

Although the annually recursive nature of the AUSM dictated an entirely different structure for the planning module, certain features of the TRI approach were retained. Among these was a two-part capacity needs test (available capacity and available energy) that required only minimal information about the states' load profiles. Another was the idea of "building toward" a specified mix of generating technologies. TRI's implementation of this latter feature was discarded because its probabilistic basis yielded results that could not be reproduced from one run to the next; the AUSM approach achieves the same goal with reproducible results.

The heart of the AUSM capacity planning module is the establishment and annual modification of the construction schedule of an utility. This unique structure, embedded in the model's annually recursive framework, simulates the utility's response to the evolving discrepancies between old demand forecasts (the basis for its current construction program) and new, revised forecasts based on new prices and the previous year's actual demand. The module operates at the individual unit level, advancing and deferring single units as required. Construction cost outlays are tabulated in such a way as to facilitate calculation of interest during construction and of real escalation of costs.

A serious shortcoming of the TRI approach was its total reliance on several user-specified parameters: the mix of generating technologies, plant retirement dates, and the schedule for conversion of oil- and gas-fired plants to coal. Economic optimization models, such as those employed by most utilities and by ICF [2], employ linear programming algorithms to deal with such factors on an economic basis. The advantage of that methodological approach is its ability to quantify costs involved in tradeoffs among various technology choices, early plant retirement, and conversion. However, the approach does not lend itself to simulation of the rescheduling realities faced by the industry due to uncertain demand forecasts. In problems as large and complex as this one (which deals with individual units), perfect certainty must be assumed in order for the optimization approach to be viable.

The state level AUSM, therefore, leaves it to the user to specify these inputs, as in the TRI model. However, the national version employs aggregated optimization models (MPMS), to simulate and quantify such tradeoffs as scrubber retrofit versus early plant retirement, coal conversion, and out-of-state siting to meet regional emission limits. This version of the planning module has been designed to accept as inputs the results of such optimization analyses, instead of relying solely on user-specified inputs.

7.2 Analytical Structure

7.2.1 Scheduling Algorithm

The central task of the capacity planning module is to maintain a schedule for the construction of generating units that best matches the capacity needs implied by the computer simulation in progress. Capacity requirements are based on the demand for electricity, which the demand module calculates on an annual basis over a look-ahead horizon at least as long as the maximum plant construction period. The planning module sets up the initial construction schedule in the first year by cataloging units in the initial unit inventory file that are slated with a future on-line date.

For each year that the planning module is run, a two-part capacity needs test, is performed successively for each year in the look-ahead horizon. If both parts are passed, steps are taken to defer units under construction; otherwise, capacity augmentation is undertaken. Capacity augmentation occurs if any part of the capacity needs test fails. It consists of two phases: (1) advancement of scheduled units, and (2) scheduling of new units. The scheduling phase takes place only if sufficient capacity cannot be brought on-line in the current horizon year by advancing scheduled units. Either phase stops when sufficient capacity has been added to pass all two tests in the horizon year. Figure 7-1 summarizes the logic of the capacity planning module.

7.2.2 Two-Part Capacity Needs Test

In year k, success in each part of the capacity needs test is defined as follows:

1. Annual energy requirements can be met by available capacity without exceeding limitations imposed by planned and unplanned outages:

$$\sum_{i=1}^{ntech} C_{ik} * F_i * 8760 > Q_k \tag{1}$$

2. The peak load can be met by available capacity:

$$\sum_{i=1}^{ntech} C_{ik} * A_i > P_k \tag{2}$$

where ntech = number of generating technologies

C_{ik} = capacity in year k of generating units of technology i (MW)

P_k = peak load in year k (MW)

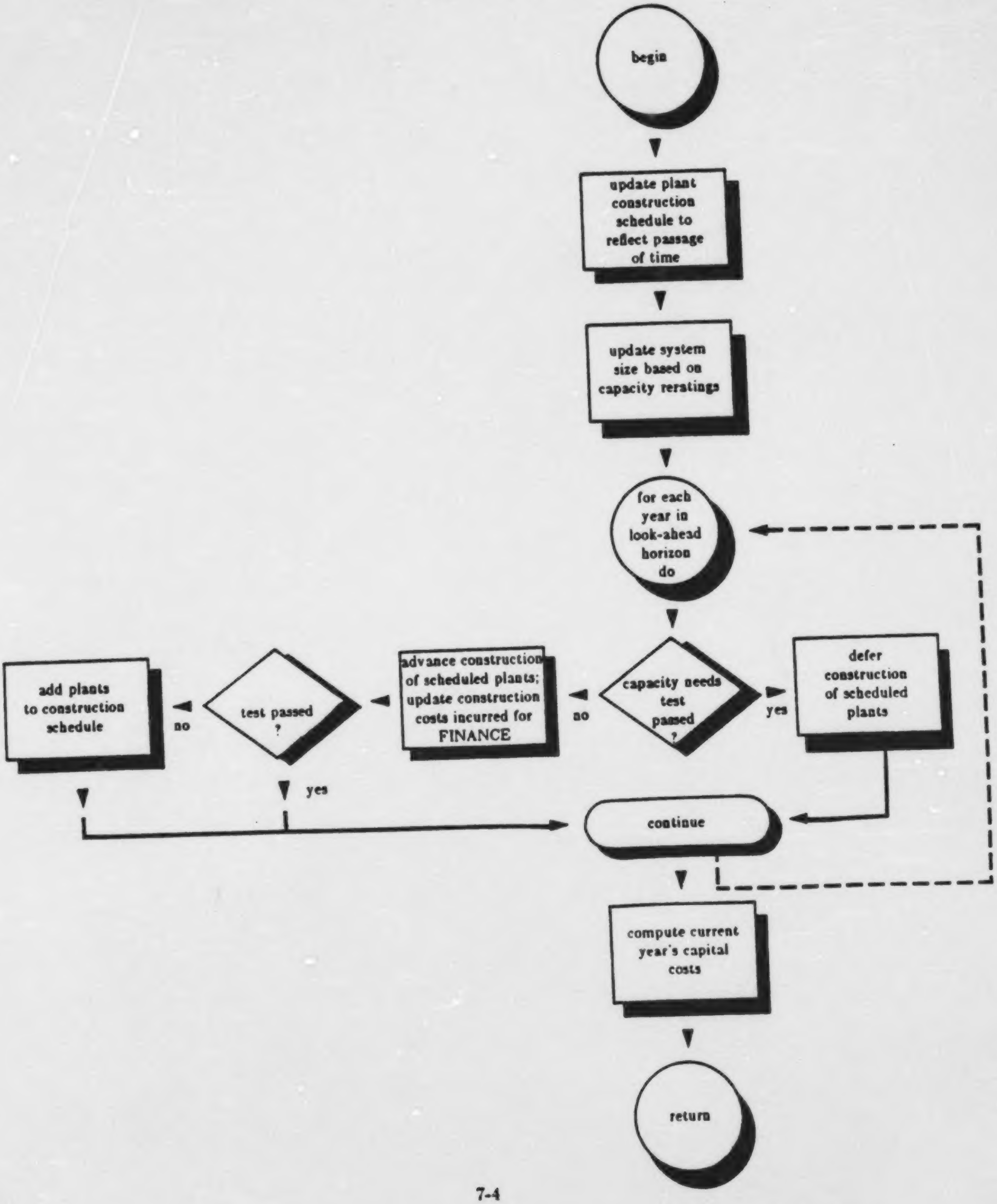
A_i = peak day availability of generating technology i

Q_k = quantity of electricity demanded in year k (MWh).

Prior to carrying out the scheduling algorithm in a given year (IYR), the planning module accesses the following data from the demand module:

$$(P_k, Q_k; k = IYR, IYR + 11).$$

Figure 7-1
SUMMARY OF CAPACITY PLANNING CONTROL FLOW


begin
update plant construction schedule to reflect passage of time
update system size based on capacity reratings
for each year in look-ahead horizon do
capacity needs test passed ?
yes
defer construction of scheduled plants
no
advance construction of scheduled plants; update construction costs incurred for FINANCE
test passed ?
no
add plants to construction schedule
yes
continue
compute current year's capital costs
return

The two measures of system size correspond to the left-hand sides of the two tests. They are, respectively, annual energy requirement and peak power. These measures of system size are initialized during a first scan of unit inventory to reflect the current system size over a 41-year period (11 years beyond the maximum simulation period, to allow representation of construction starts for units having 11-year construction periods). System size accumulations are updated each time alterations are made to the construction schedule.

The array EXCESS(2) contains the differences between projected needs and projected capacity. The components of this array correspond to each part of the test. For horizon year k of simulation year IYR,

$$EXCESS_{i=1,2} = C_{i,k+IYR} - D_{i,k+IYR} > 0 \qquad (3)$$

where $C_{i,k+IYR}$ = projected system size as defined by test i in horizon year k

$D_{i,k+IYR}$ = projected demand as defined by test i in horizon year k.

Alterations made to the construction schedule affect the value of $C_{i,k+IYR}$ and are carried out with the goal of bringing each value of EXCESS as close to zero as possible. The test is considered "passed" if the value of EXCESS is positive and less than 2 percent of projected demand. This interval, which is coded into the program, reduces the number of deferrals simulated by the annually recursive model in response to minor year-to-year changes in projected electricity demands. It probably reflects utility behavior accurately in light of the uncertainties inherent in demand forecasts, recognizing the labor difficulties and other factors involved in deferring construction. Schedule alterations are made as described in Sections 7.2.3 and 7.2.4, below, by deferring or advancing scheduled plants or by adding new plants to the construction schedule.

7.2.3 Advancements and Additions of Scheduled Plants

Capacity augmentation protocol is undertaken for each horizon year that projected capacity is insufficient to pass all two parts of the capacity needs test. If sufficient capacity cannot be brought online in the current horizon year by advancing currently scheduled plants, new plants are slated for construction. Plants are always advanced or scheduled so as to be brought on-line in the horizon year.

The entire list of scheduled plants is examined for possible advancement. Those candidates selected must meet four criteria:

1. The scheduled year on-line is later than the horizon year.

2. Enough years remain prior to the horizon year to complete construction.

3. If a unit is nuclear-fueled, then either construction is less than the scenario-specified percent complete, or a user-specified "new nuclear year" has passed (see Section 7.3 for a description of the input data).

4. The plant is not an existing plant scheduled for oil-to-coal conversion.

In addition, there is a scenario parameter (BDYR) which specifies the year before which no unit may be advanced or scheduled. This is normally set to the year in which AUSM data base on announced plants was last updated, to keep the model from scheduling nonexistent plants while it is simulating historic years such as 1980. Prior to that year, the only plants that may be advanced are those that have previously been deferred. Among this group of candidates, units whose construction has been deferred are ranked above those whose construction has not yet begun. Deferred plants are ranked for advancement in descending order of construction cost incurred to date. The remaining (nondeferred) candidates are ranked as a function of the combination of test parts failed. In particular, if part 1 has failed, then base and intermediate units are ranked before peakers. If part 2 has failed, then peakers are given the higher priority.

The technology of new generating units is selected with the objective of matching the user-specified future mix. The domain for selection, however, is delimited by two factors:

1. The decision to add new nuclear plants may not be made prior to the new nuclear year.

2. A technology may not be selected if there is insufficient time to build that type of plant prior to the horizon year.

A plant of technology k is selected for scheduling only if, in the appropriate horizon year,

$$F_m - \frac{MW_m}{MW_T} > (F_i - \frac{MW_i}{MW_T}) \text{ for all } i \neq m \qquad (4)$$

where F_m = user-specified future mix for technology m

MW_m = new generating capacity of type m scheduled to date

MW_T = total new generating capacity scheduled to date.

Newly scheduled plants are added to the unit inventory file at the same time they are added to the construction schedule.

The technology mix $\{F_m\}$ is simply a target to build toward, rather than a rigid constraint to be met each year. The actual fraction during any year will depend on differences in construction lead times, the number and types of plants previously announced, which capacity needs tests have failed, and scenario-induced patterns of advancements and deferrals. The actual technology mix eventually converges to the target value after the temporary effects of these factors diminish.

In some simulations, due to combinations of extreme values of scenario parameters selected by the user, projected demand may grow so fast that it would be necessary to depart radically from the target mix of generating technologies. For example, the program may simulate construction of hundreds of peaking plants in order to meet demand in the short term, because of the long lead time required to complete baseload plants already scheduled or under construction. Such outcomes are obviously unrealistic, and they can be quite costly in terms of computer time and storage needed to accommodate them. Therefore, a ceiling is coded into the program to ensure that the technology mix fraction actually scheduled never exceeds the target mix by more than a factor of three. In such cases, which are rare, the capacity tests go unmet and the dispatching module is forced to buy "emergency purchased power" to make up the shortfall.

When the technology mix is specified by MPMS instead of by the user, the target mix will vary as a function of time, reflecting economic considerations that affect the optimal mix of generating technologies over time. The "foresight" obtained from the "look-ahead" capability of MPMS is therefore exploited in the AUSM in the following manner. The value of F_m in Equation 5 is set equal to the cumulative mix of new generating capacity forecast by MPMS to be brought on-line during the simulation period of interest. This rather simple interface will be tested first, and if it is found to be inadequate a more complex interface could be developed to allow for F_m to vary as a function of time.

The look-ahead capability of MPMS allows it to determine when it is optimal to accelerate retirement of old plants and replace them with newer, cleaner plants. In such cases, the two-part capacity needs test must be modified to force the additional construction. This is done by passing two factors from MPMS representing the ratios: 1) available capacity/peak demand; and 2) maximum annual generation/annual generation requirements. These ratios are calculated in MPMS using the availability and maximum capacity factors, and used in the AUSM capacity planning module to multiply the projected peak demands and energy requirements in the capacity test. The ratios vary as a function of time.

7.2.4 Deferrals of Scheduled Plants

Scheduled plants become candidates for deferral if they are (1) scheduled to be brought on-line in the horizon year; (2) less than a user-specified percentage from completion by total construction expenditure; (3) not existing plants scheduled for oil-to-coal conversion. Candidates are ranked in ascending order of construction expenditure to date.

Plants are deferred until either (1) all candidates have been deferred or (2) the deferral of any remaining candidate would cause one or more parts of the two-part test to fail. A plant ranked low on the list is deferred and a large high-priority plant is completed if deferral of the high priority plant would cause failure of the two-part test. Plants are deferred so as to be brought on-line one year after the horizon year. Since plants are selected for deferral only if they are scheduled to be on-line in the current horizon year, it follows that, in a single horizon year, plant construction can be deferred by one year at most. However, plant deferral upon completion of the full scheduling algorithm can total several years.

In order to allow the user to specify definite completion dates for certain plants already under construction, there is a scenario parameter (BPOLD) which sets a deferral cut-off year for baseload plants (i.e., those with technology codes of 15, 16, 17, or 18). If the on-line year of a plant is less than the specified cutoff year, that plant may never be deferred.

7.2.5 Pollution Penalties

Construction schedule modifications are based on total generation computed after allowances have been made for pollution control devices. System size adjustments are made prior to implementation of the central scheduling algorithm by scanning for units with, respectively, sulfur dioxide, oxides of nitrogen, or particulate control devices coming on-line in the current year. For each device added, the retirement date for the corresponding unit is retrieved from the unit inventory file. The system size arrays are then reduced for the remaining lifetime of the newly retrofitted plants.

7.2.6 Transmission, Distribution, and General and Administration Costs

Following TRI [2], it is assumed that capital and operating costs of transmission equipment are proportional to the peak demand (megawatts) experienced to date, and that costs of distribution facilities and general and administrative costs are proportional to the peak annual generation (megawatt hours per year) experienced to date. Therefore, for each simulation year, the capacity planning module performs the custodial task of updating current construction expenditures for transmission, distribution, and general and administrative. These values are calculated as follows:

$$TF = \Delta P * TFC \tag{5}$$

$$DF = \Delta G * DFC \tag{6}$$

$$AF = \Delta G * AFC \tag{7}$$

where TF = current year construction expenditure for transmission ($/yr)

ΔP = increase in maximum peak demand since last peak (ΔMW)

TFC = fixed transmission cost ($/yr/$\Delta$MW)

DF = current year construction expenditure for distribution (\$/yr)

ΔG = increase in net generation since last peak (ΔMWh)

DFC = fixed distribution cost (\$/yr/ΔMWh)

AF = current year construction expenditure for general and administrative plant (\$/yr)

AFC = fixed cost of general and administrative plant (\$/yr/ΔMWh).

Similarly, it is assumed the operating and maintenance costs of transmission are proportional to peak demand and that distribution and general and administrative costs are proportional to the amount of electricity generated. These values are calculated as follows:

$$TV = P*TVC \tag{8}$$

$$DV = G*DVC \tag{9}$$

$$AV = G*AVC \tag{10}$$

where TV = current year expenditure for transmission O&M (\$/yr)

P = current year peak demand (MW)

TVC = variable transmission cost (\$/yr/MW)

DV = current year expenditure for distribution O&M (\$/yr)

G = current year net generation (MWh/yr)

DVC = variable distribution cost (\$/MWh)

AV = current year expenditure for general administration O&M (\$/yr)

AVC = general and administration variable cost (\$/MWh).

Unit costs were obtained from 1980 data for privately owned electric utilities from the Federal Energy Regulatory Commission (FERC) (see Section 7.3).

7.2.7 Nuclear Moratorium

The planning module uses two scenario variables to simulate the effect of a moratorium on the construction of nuclear plants. The variable NEWNUC defines a year before which nuclear plants may not be scheduled. This allows the user to specify a nuclear moratorium. To deal with plants already under construction, the variable NUCFRC defines a user-specified fraction of construction costs that must have been completed if construction of a nuclear plant will be continued prior to the "new nuclear year."

7.2.8 Conversions

Plants to be converted from oil or natural gas to coal are indicated by entries in the unit inventory file before the model is run. A retirement date is shown for the oil or coal unit, and a new coal plant is shown as an "announced plant" scheduled for completion that same year. In the unit inventory file, the new plant may be assigned a different capacity, heat rate, and retirement date to reflect changes due to its conversion. Conversions are neither advanced nor deferred.

7.3 Data Choices

Default values of user-specified scenario variables used by the capacity planning module are listed in Table 7-1. This section documents the selection of all data used as inputs to the capacity planning module. Default values of all input data files are shown in the remaining tables in the section.

Table 7-1
SCENARIO VARIABLES USED BY THE CAPACITY PLANNING MODULE

Global Variable	*Default Value or Data Source*
MPMS switch	0=normal; 1=MPMS run
Non-nuclear construction cost escalation rate	0.00
Nuclear construction cost escalation rate	0.00
Construction completion fraction for deferrals	0.50
Year before which baseload plants may not be deferred	1980
Year before which units may not be advanced	1980
State Variable	*Default Value or Data Source*
1980 coal steam unit construction cost	$770 per kilowatt
1980 light water reactor construction cost	$1050 per kilowatt
Conversion cost: oil or gas to coal	$200 per kilowatt
Year nuclear moratorium ends	1980
Construction completion fraction for nuclear moratorium	0.00
Target mix of generating technologies	0.90 coal steam 0.05 gas combustion turbine 0.05 distillate oil combustion turbine

7.3.1 Data on New Generating Units

Data on the cost and operating characteristics of 23 electricity generating technologies are available from a variety of sources, and many are quite controversial. Perhaps the most widely used data, generally accepted throughout the electric utility industry, are those published by the Electric Power Research Institute (EPRI) [3]. These data, which are updated biannually, were used as the basis for AUSM default values.

Data on heat rates, construction periods, lifetimes, and construction costs were taken directly from the EPRI report. Note that construction costs may be overridden on a state-by-state basis using a scenario variable. Nonfuel operation and maintenance (O&M) costs shown in Table 7-2 represent the sum of fixed and variable cost components. Construction costs for coal steam units include all pollution control-related costs except for flue gas desulfurization (FGD) costs, which are added by the pollution control module. The cost of converting gas- and oil-fired plants to coal also excludes scrubbers. This cost has been estimated by ICF [4] to range from $115 to $340 per kilowatt, depending on whether the plant has ever burned coal before and how much of the coal-burning equipment is still in place, and by Burns and Roe [5] at about $195. An average value of $200 per kilowatt is therefore assumed as the default value of this user-specified variable. Because peak day availability and maximum annual capacity factors are not reported directly by EPRI, some analysis was required to obtain the default values for these two parameters (see below).

7.3.1.1 **Peak Day Availability.** It is assumed that planned outages can be scheduled to avoid peak periods. Therefore, the capacity available on the peak day may be defined as follows:

$$\textit{peak day availability} \equiv (1 - EUOR) \tag{11}$$

where EUOR is the equivalent unplanned outage rate.

$$EUOR \equiv \frac{\textit{unplanned outage hours} + \textit{equivalent unplanned derated hours}}{\textit{period hours} - \textit{planned outage hours}} \tag{12}$$

Estimates of equivalent unplanned outage rates are published by EPRI [3] for new coal and nuclear units. The values given are 0.179 for coal units and 0.217 for nuclear units, implying peak day availabilities of 0.821 and 0.783, respectively.

The same type of data may also be obtained for actual operating power plants from the National Electric Reliability Council (NERC) Generating Availability Data System (GADS) [6]. GADS is based on

Table 7-2
GENERATING TECHNOLOGIES

	Availability (fraction)	Maximum Capacity Factor (fraction)	Heat Rate (Btu/KWh)	Construction Period (years)	Expected Lifetime (years)	Unit Capacity (MW)	Nonfuel O&M (mills/KWh)	Construction Cost (1980$/KW)
Peaking Plants								
1 Gas combustion turbine	.920	.891	13,800	3	20	75	3.43	215
2 Distillate oil combustion turbine	.920	.891	13,800	3	20	75	3.43	215
3 Residual oil combustion turbine	.900	.871	14,000	3	20	75	3.93	235
4 Hydro-pumped storage (underground)	.979	.959	0	9	50	667	1.17	680
Intermediate and Cycling Plants								
5 Conventional gas steam	.887	.802	9680	7	30	500	2.09	545
6 Conventional distillate oil steam	.887	.802	9680	7	30	500	2.09	545
7 Conventional residual steam	.887	.802	9680	7	30	500	2.09	715
8 Solvent refined coal	.887	.802	9700	7	30	500	4.17	800
9 Gas combined cycle	.926	.861	8600	4	30	500	2.81	425
10 Distillate oil combined cycle	.926	.861	8600	4	30	500	2.81	425
11 Residual oil combined cycle	.904	.841	8685	4	30	250	3.48	490
12 Pressurized fluidized bed combined cycle	.851	.769	8720	8	30	650	6.07	830
13 Gasification combined cycle	.911	.811	9740	7	30	1000	5.61	995
14 Gasifier - gas-fired boiler	.847	.754	9955	8	30	1000	8.76	1035
Baseload Plants								
15 Coal steam (no FGD)	.821	.567	9735	8	30	1000	2.22	770[a]
16 Light water reactor (pressurized or boiling water)	.783	.576	10,700	11	30	1000	3.39	1050[a]
17 Bituminous atmospheric fluidized bed	.835	.755	9930	8	30	500	5.90	780
18 Sub-bituminous atmospheric fluidized bed	.835	.755	10,130	8	30	500	3.20	750
Renewables and Other								
19 Hydroelectric dam	.900	.900	0	5	60	200	0.71	656
20 Magnetohydrodynamic combined cycle	.717	.632	9320	10	30	100	4.25	1240
21 Geothermal (brine solution)	.0	.0	28,320	4	30	50	8.20	740
22 Dispersed fuel cells	.944	.906	8300	3	20	10	3.68	595
23 Solar central receiver	.0	.0	10,100	5	30	10	6.09	2125

[a] Scenario variable.

data voluntarily submitted by more than 100 participating utilities. Summary data for the 1970-79 period show equivalent forced outage rates of 0.228 for coal units and 0.175 for nuclear units, implying peak day availabilities of 0.772 and 0.825, respectively.

Because the actual data are for an incomplete sample of baseload units and do not differ substantially from the EPRI estimates, the EPRI figures were chosen for the AUSM default data.

7.3.1.2 **Maximum Annual Capacity Factor.** Maximum annual generation is limited not only by forced outages, but also by planned outages. The utility industry therefore defines a parameter called "equivalent availability" as follows:

$$\textit{equivalent availability} \equiv (1 - EUOR)\,(1 - \textit{planned outage rate}) \tag{13}$$

EPRI [3] estimates the value of this parameter at 0.743 and 0.682 for new coal and nuclear units, respectively. NERC [6] reports 0.662 and 0.665, respectively, for its sample of plants 575 megawatts and larger that operated during the 1970-79 period. Apparently, planned outages are more lengthy in practice than foreseen by designers.

It would be unrealistic to assume that equivalent availability is an achievable maximum value for the annual capacity factor; it is an upper limit, which cannot be reached in practice for a variety of reasons that are discussed below. EIA [7] reported an *actual* average capacity factor of 0.576 for nuclear plants in 1980, and Pechan [8] reported that coal-fired units larger than 400 megawatts averaged only a 0.567 capacity factor in 1980. Pechan's analysis excluded units that had been on-line less than 2 years (to exclude problems associated with startup) and more than 16 years (to exclude aging baseload plants that may have been relegated to cycling operation). This discrepancy between "equivalent availability" and "actual capacity factor" can be attributed to three major factors, which must be understood before a modeling parameter "maximum annual capacity factor" can be defined.

The first factor is the most difficult to quantify: plants are run at less than full capacity during periods of low loads, especially during spring and fall weekends, and weeknights when industrial load is lowest. The second factor, identified by Toscas [9], is that plants are run at less than full capacity even during periods when system load exceeds the aggregate capacity of all large coal and nuclear baseload units. This is because system-specific spinning reserve requirements may dictate that a significant number of smaller plants be operating at reduced capacity at all times. The NERC data contain only limited information on this effect, reporting "economy outage hours" of about 2 to 3 percent per year for large coal-fired units and 0 percent for nuclear units. Unfortunately, NERC does not report partial outages in this category, only total outages. A third factor may result from gradually "ramping" the unit during startup or shutdown over a period of several days. The effect on capacity factor is given by

$$\Delta = \frac{0.5 * D * 24 * N}{8760} \tag{14}$$

where D is the number of days (startup and shutdown) of partial operation associated with each of the shutdowns per year. NERC reports $N \approx 15$ for nuclear units and $N \approx 25$ for large coal units. Therefore, it follows that

$$\textit{coal:} \quad \Delta = .034\, D \tag{15}$$

$$\textit{nuclear:} \quad \Delta = .021\, D. \tag{16}$$

Clearly, this can be a significant effect if D is on the order of one or more days, and these days are not included in the planned and unplanned outage statistics.

From a modeling standpoint, it is difficult to adjust "equivalent availability" downward to estimate a realistic "maximum annual capacity factor" that would constrain the dispatching algorithm. The principal difficulty is that spinning reserve requirements are highly system-specific, as are the impacts of the "ramping" requirements. Moreover, precise data on the shape of the load duration curve is unavailable for the past and present, and highly uncertain for future years. Therefore the AUSM dispatching module's representation of the load curve is extremely coarse, and its step-function shape necessarily overestimates demand for baseload generation. For these reasons, it is most efficient to approximate the aggregate effect of all these factors by defining a "maximum annual capacity factor" significantly lower than the reported values for "equivalent availability." Therefore, the 1980 actual capacity factors cited above for coal and nuclear baseload plants were selected as default values for the AUSM. Users familiar with the actual situation for particular states and generating units may wish to alter these values. Sensitivity analyses performed to date indicate that capacity factor is rarely the binding constraint in the planning module's two-part capacity needs test, but is quite often a binding constraint in the dispatching module's simulation of generation by individual units.

7.3.2 **Distribution of Construction Costs**

Table 7-3 shows the distribution of construction costs throughout the plant construction period. These data are essential because they allow calculation of interest during construction accumulated during periods when the construction is interrupted or deferred and permit the financial module to account for construction work in progress. The data were available only from Bechtel [10]; they sometimes imply construction periods shorter than those defined by EPRI. In such cases, the EPRI data on construction periods were retained, and zeros were inserted in the initial years to reflect planning and licensing lead times. When no data were given by Bechtel (e.g., for solar plants), a uniform distribution of expenditures was assumed.

7.3.3 **Costs of Transmission and Distribution Facilities**

The undepreciated book value in mixed nominal dollars of plant costs and operating characteristics (e.g., capacity and energy generated) are compiled for private utilities by the U.S. Federal Energy Regulatory Commission and reported by the Energy Information Administration [11]. The book value of a plant is the total cost of all facilities still in use. The cost of new facilities would be considerably higher than those inferred from the book value, since the book value is expressed in mixed current dollars. To infer the 1980 marginal cost, a multiplicative factor *f* is calculated that converts the mixed unit costs into real (1980) dollars:

$$f = C_{80}A_{80} / \sum_{t=1980-T}^{1980} C_t(A_t - A_{t-1}) \qquad (17)$$

where C_t = unit cost of facilities in year t

A_t = capacity or energy demand in year t

T = facility lifetime.

Table 7-3
CONSTRUCTION COST DISTRIBUTION
(percentage spent per construction year)

Technology Type	Stage of Construction (years) 1	2	3	4	5	6	7	8	9	10	11
Peaking Plants											
1 Gas combustion turbine	0	10	90								
2 Distillate oil combustion turbine	0	10	90								
3 Residual oil combustion turbine	0	10	90								
4 Hydro-pumped storage (underground)	0	0	0	2	12	25	27	20	14		
Intermediate and Cycling Plants											
5 Conventional gas steam	0	0	0	10	30	35	25				
6 Conventional distillate oil steam	0	0	4	18	32	26	20				
7 Conventional residual steam	0	0	4	18	32	26	20				
8 Solvent refined coal	0	0	4	18	32	26	20				
9 Gas combined cycle	0	0	10	90							
10 Distillate oil combined cycle	0	0	10	90							
11 Residual oil combined cycle	0	0	10	90							
12 Pressurized fluidized bed combined cycle	0	0	0	4	18	32	26	20			
13 Gasification combined cycle	0	0	4	18	32	26	20				
14 Gasifier - gas-fired boiler	0	0	0	4	18	32	26	20			
Base Load Plants											
15 Coal steam power plant	0	0	0	4	18	32	26	20			
16 Light water reactor (pressurized or boiling water)	0	0	1	2	3	11	18	27	22	11	5
17 Bituminous atmospheric fluidized bed	0	0	0	4	18	32	26	20			
18 Sub-bituminous atmospheric fluidized bed	0	0	0	4	18	32	26	20			
Renewables and Other											
19 Hydro electric dam	0	7	32	36	25						
20 Magnetohydrodynamic combined cycle	0	0	0	0	0	4	18	32	26	20	
21 Geothermal (brine solution)	10	34	22	34							
22 Dispersed fuel cells	0	23	77								
23 Solar central receiver	0	25	25	25	25						

The facility lifetime, T, is also the period of time over which the book value is accumulated. When C_t and A_t are expressed in terms of their 1980 values using the inflation rate, i, and the electricity demand growth rate, g, the 1980 values cancel out of Equation 18, leaving

$$f = \frac{\{[(1+g)(1+i)]^{T} - [(1+g)(1+i)]^{T-1}\}\{(1+g)^{T} - 1)\}}{\{[(1+g)(1+i)]^{T} - 1\}\{(1+g)^{T} - (1+g)^{T-1}\}}. \tag{18}$$

Assuming that the lifetime of a plant is 50 years, the book value represents plant added from 1930 to 1980. During this period, the average inflation rate as indicated by the implicit GNP deflator reported by the U.S. Bureau of the Census [12] and EIA [7] was 0.0317. The demand for electricity grew at an average rate of g = 0.0708, according to the Census Bureau [12] and EIA [11]. Substituting these values into Equation 19 yields f = 1.398. Due to this high growth rate, the facilities in place in 1930 can be neglected, and the 1980 marginal cost approximated by using f to adjust each state's reported book value to 1980 dollars, and dividing by the 1980 capacity and generation. Table 7-4 shows the results obtained for each state. Since data were unavailable for Nebraska, which has no investor-owned utilities, it was assigned the same value as Kansas.

A more detailed analysis of data for each of the 48 states and a discussion of alternative methodologies considered and rejected is given by Culkeen and Stiles [13].

7.4 Stand-Alone Module Results

The reports generated during each AUSM simulation summarize most of the relevant outputs of the planning module. However, they do not show the details of alterations to the construction schedule, which is the heart of the planning module.

Figure 7-2 shows how the demand forecast varies during a typical simulation for Illinois. These shifts in expected demand create the need to advance and defer many of the 140 new power plants considered in the construction schedule during the 30-year period. Figure 7-3 shows construction flowsheets for 9 of these plants.

The simulation begins with plants already planned or under construction. During the early 1980s, several large baseload plants are brought on-line. At the same time the expected demand growth rate

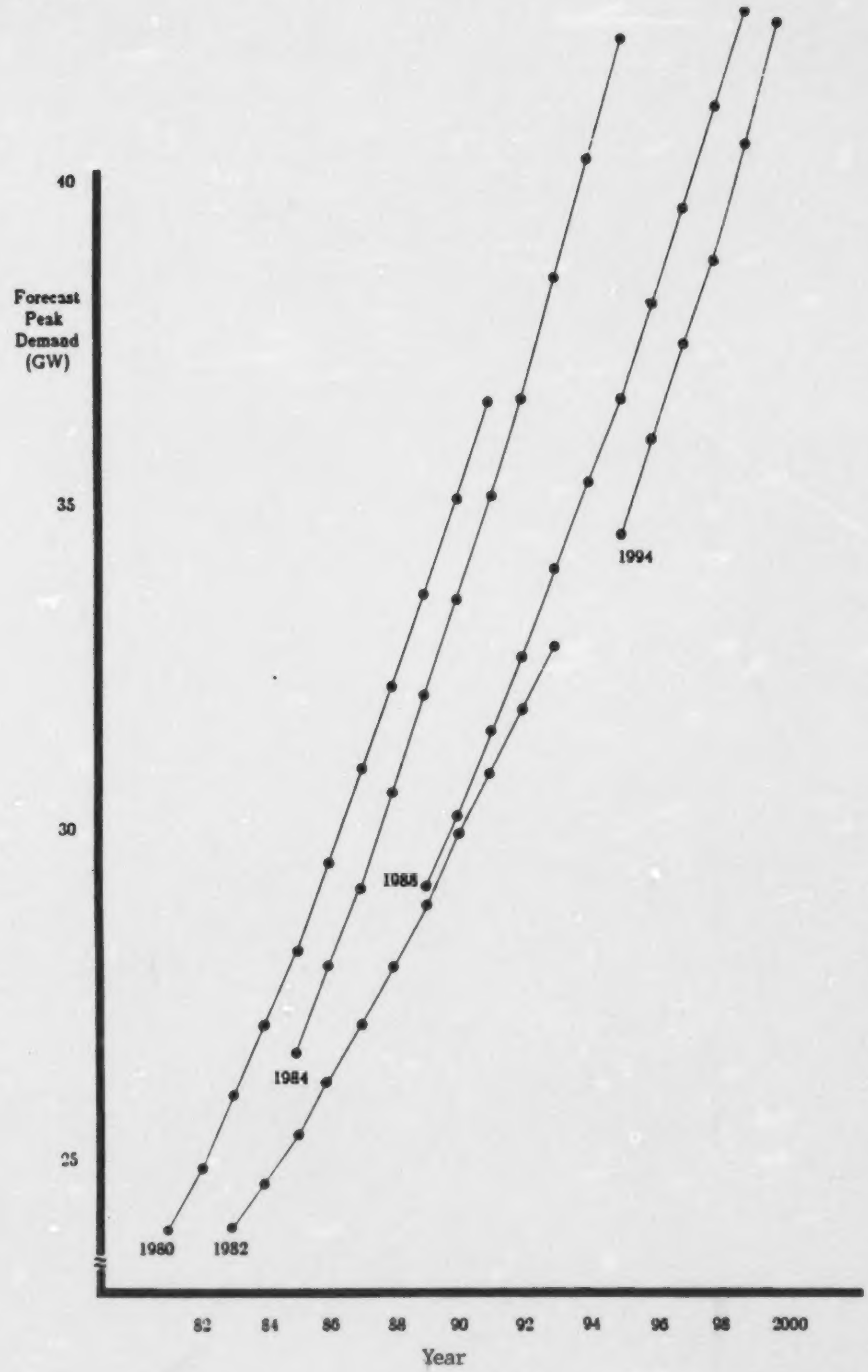
Table 7-4
STATE PLANNING DATA
(in 1980 dollars)

State	Capital Costs			O&M Costs		
	Transmission ($/yr/ ΔKW)	Distribution ($/yr/ ΔMWh)	General Plant and Intangibles ($/yr/ ΔMWh)	Transmission ($/yr/KW)	Distribution ($/yr/MWh)	General Plant and Intangibles ($/yr/MWh)
Alabama	99.750	.041	8.498	1.419	.877	1.694
Arizona	170.500	.072	7.978	1.882	1.083	15.410
Arkansas	84.310	.048	2.182	.761	.624	2.335
California	126.500	.081	3.005	2.770	1.882	2.875
Colorado	82.950	.075	1.718	1.190	1.456	2.846
Connecticut	78.150	.071	5.815	2.311	2.327	2.641
Delaware	153.800	.065	6.708	2.841	2.329	3.200
Florida	77.00	.059	6.720	1.242	1.667	2.384
Georgia	72.65	.054	11.500	1.260	.936	2.220
Idaho	123.200	.046	4.801	1.534	.976	1.619
Illinois	97.160	.060	6.024	1.446	1.380	2.132
Indiana	72.330	.029	6.422	1.438	.893	1.421
Iowa	108.800	.072	5.834	1.531	1.670	2.427
Kansas	86.080	.049	4.806	1.236	1.164	1.641
Kentucky	87.490	.043	3.393	1.289	1.330	1.368
Louisiana	68.50	.040	3.111	.842	.948	1.315
Maine	122.100	.038	5.565	3.327	1.130	1.535
Maryland	830.87	.056	1.394	2.012	1.819	2.568
Massachusetts	92.820	.051	3.014	3.940	1.418	1.965
Michigan	107.900	.058	6.458	1.619	1.746	3.140
Minnesota	96.630	.046	6.259	1.373	1.492	2.437
Mississippi	73.140	.032	3.380	1.024	.995	1.496
Missouri	71.080	.068	7.860	1.008	1.465	2.083
Montana	181.700	.038	5.002	3.745	1.051	1.555
Nebraska	86.080	.049	4.806	1.236	1.164	1.641
Nevada	123.500	.063	5.269	1.081	1.162	2.029
New Hampshire	142.600	.059	6.496	3.859	1.636	2.806
New Jersey	99.720	.078	2.852	2.219	1.670	2.848
New Mexico	86.570	.048	7.043	.936	1.116	3.748
New York	152.600	.090	4.010	3.630	2.770	3.577
North Carolina	81.650	.041	6.180	1.343	.907	1.460
North Dakota	182.800	.062	11.690	4.372	1.706	3.075
Ohio	92.110	.039	5.527	1.733	1.119	1.506
Oklahoma	64.680	.038	4.308	.793	.950	1.287
Oregon	126.300	.055	8.367	4.050	.972	1.816
Pennsylvania	78.970	.073	6.531	2.020	1.974	2.249
Rhode Island	288.700	.096	4.321	10.130	2.348	2.948
South Carolina	69.260	.052	3.493	.745	.807	1.473
South Dakota	214.700	.069	14.470	2.788	1.783	3.441
Tennessee	80.080	.020	3.410	3.716	.577	1.278

Table 7-4 (contd.)

	Capital Costs			O&M Costs		
State	Transmission ($/yr/ΔKW)	Distribution ($/yr/ΔMWh)	General Plant and Intangibles ($/yr/ΔMWh)	Transmission ($/yr/KW)	Distribution ($/yr/MWh)	General Plant and Intangibles ($/yr/MWh)
Texas	57.530	.039	6.202	.829	1.028	1.790
Utah	195.800	.047	24.520	1.565	1.410	2.187
Vermont	161.200	.024	2.109	10.850	.752	1.393
Virginia	79.060	.060	3.392	.634	1.396	1.623
Washington	143.900	.066	7.609	7.967	.979	1.431
West Virginia	111.600	.034	1.962	1.573	1.026	.979
Wisconsin	83.080	.061	5.902	1.704	1.999	2.409
Wyoming	85.740	.079	.324	35.230	1.579	1.624

Figure 7.2
FORECASTS OF PEAK DEMAND



decreases, partly due to the effect of the new plants on electricity rates. Therefore, several plants under construction are deferred for short periods during the early 1980s, and several new starts are deferred until the middle to end of the decade.

By 1984 there is an increase in forecasted demand, and several plants are advanced. The first peaking plant shown in Figure 7-3, for example, has its deferral shortened, while other scheduled plants have their construction starting dates advanced. During the 1984 to 1988 period many small peaking plants are completed.

A third distinct phase begins around 1988, when the electricity demand forecast drops. This implies that several large plants are deferred, including many of those begun during the "growth" phase around 1984. The sixth, seventh and eighth plants shown in Figure 7-3 demonstrate the effect.

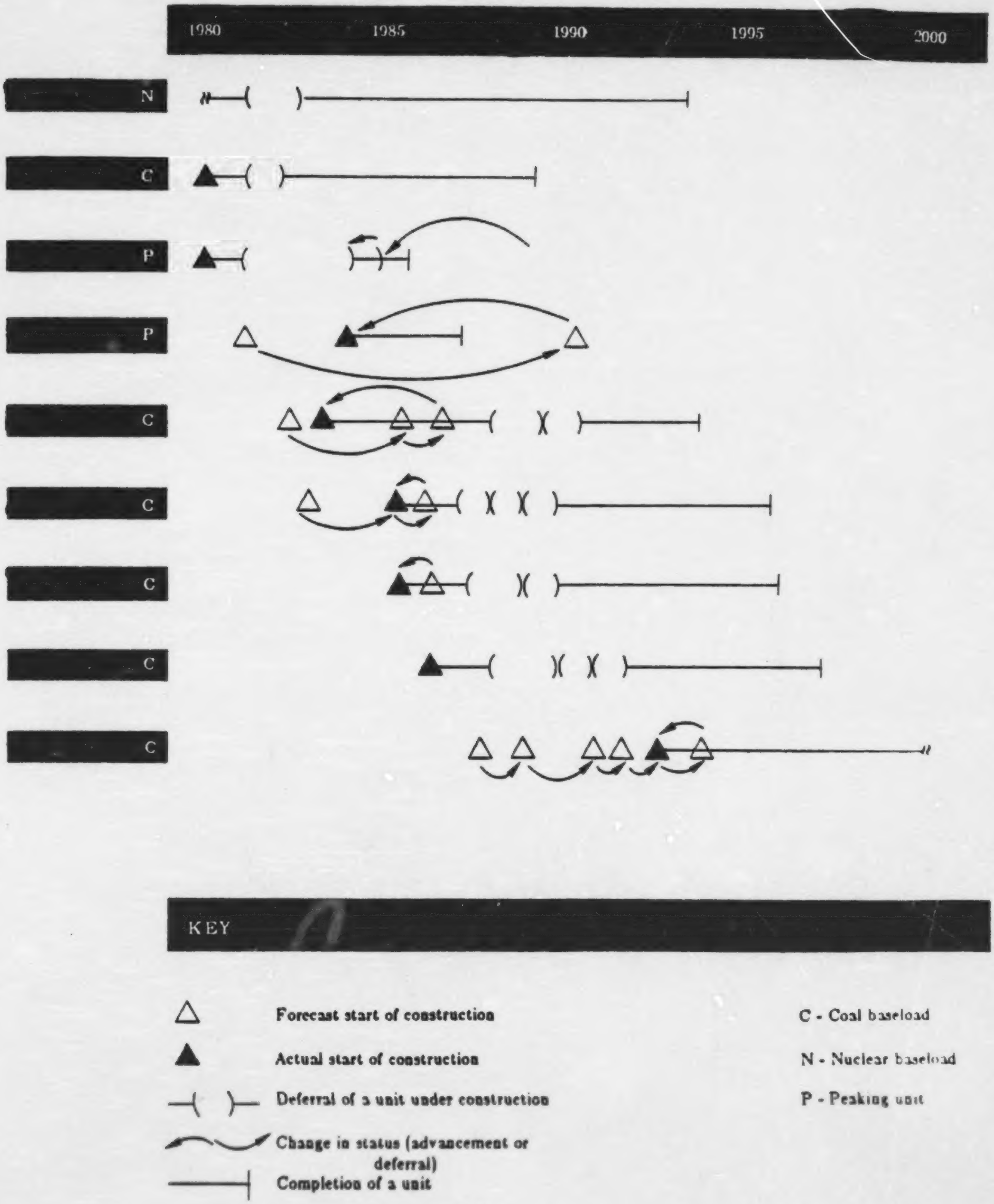
Throughout the 1990s, electricity demand forecasts are relatively stable. Thus, baseload plants, once begun, are completed with only minor deferrals.

One of the inputs to the simulation calls for a 90/10 split between base and peaking capacity added. This is specified as a target to build toward, not a rigid requirement. As the simulation proceeds, an excess of peaking plants is added during the "growth phase"; cumulative additions result in a 60/40 mix in 1985. By the mid-1990s, however, cumulative additions reach the 90/10 target mix, and the ratio remains quite stable throughout the balance of the simulation period.

7.5 Summary and Conclusions

The capacity planning module retains an individual unit level of detail. It builds toward a specified mix of generating technologies using an algorithm that ensures reproducible results. The capacity planning module can flexibly simulate the scheduling implications of a more realistic planning environment. This environment is characterized by uncertain demand forecasts, which change because of adjustments in the construction schedule as the financial effects of these adjustments propagate through the rate structure and elicit a demand response from users of electricity.

Figure 7-3
CONSTRUCTION SCHEDULE MODIFICATIONS



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APPENDIX A. ELECTRIC UTILITY UNIT INVENTORY

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A.1 Introduction

One of the most important data bases needed for the Advanced Utility Simulation Model (AUSM) is a comprehensive inventory representing both the physical facilities operated by the electric utility industry in the United States and the parameters of their operation relevant to the assessment and analysis of environmental issues. In addition to the sophisticated analytical requirements of the AUSM, a need was identified for a stand-alone data base that could be used for statistical analysis of the utility industry. This stand-alone data base could also contribute to simplified "scoping" analysis for those cases in which use of the AUSM would not be justified.

The unit inventory was designed to meet several criteria specified by the Environmental Protection Agency (EPA). The inventory had to be comprehensive in the sense of adequately representing the full set of environmentally important facilities operated by the electric utility industry. It also had to be complete enough to meet a variety of analytical and modeling needs. Another important requirement was that the data base be developed in a convenient automated form, with maximal reliance on other data already available within the federal government.

The unit inventory is designed to meet those analytical needs that require broad coverage of the industry as opposed to those that require much more detailed information on far fewer facilities. Since larger facilities are more significant from an environmental (and energy use) standpoint, many of the smallest facilities operated by the industry have been grouped for purposes of analysis into "generic" small units on a state-by-state basis (see section A-2).

The overall focus of the unit inventory is on *annual* operational and fuel use statistics, with 1980 as the base year. Thus, the inventory is useful in analyses requiring information on "current" conditions in the industry. To meet additional needs specified by other AUSM researchers, however, data were also included on facilities planned for future operation by the industry. It should also be noted that these other researchers specified values for various data fields in the inventory.

This appendix presents technical documentation of the unit inventory data set as of December 1982. It focuses on (1) the sources of the data elements contained in the unit inventory, (2) the assumptions that were needed in the development of the inventory, and (3) the format of the unit inventory data base as it currently exists. Section A-2 presents an overview of the sources and assumptions used in developing the unit inventory. In that section, the major emphasis is placed on understanding the inventory within the context of the entire set of data from which the unit inventory data base was developed. In Section A-3, detailed information is provided on the sources and assumptions used in developing the individual data elements in the unit inventory.

It should be noted that the unit inventory documented here is an interim 1980 data set. It is anticipated that a more accurate 1980 data base will be produced during 1983; the revised unit inventory then available will make the current version obsolete. In accordance with specifications of Task Groups B and I of the National Acid Precipitation Assessment Plan (NAPAP), a plan will also be prepared to produce a 1984 base year inventory. This plan will be prepared as soon as revisions are completed for the basic data systems operated by the Department of Energy and required by the unit inventory.

Because of the interim nature of the current version of the unit inventory, additional detail regarding the procedures used to produce this version is not included in this report and will not be prepared. These procedures are, of course, fully defined by the computer programs and data files used in creating the inventory.

A-2 Unit Inventory Overview

A-2.1 Coverage

As indicated above, the objective of the unit inventory is to provide complete coverage of the environmentally significant facilities operated by the electric utility industry in the United States. Due to the nature of the industry and its development, the range in size and significance of facilities operated by the industry is vast. Steam-powered generators, for example, vary in size by more than three orders of magnitude. Generally, much more information is available on the larger facilities.

Inclusion of *all* facilities operated by the industry, no matter how small, would have resulted in a file of over 10,000 entries. Furthermore, since little information is known about the smallest facilities, it would have been necessary to make assumptions concerning many of the key data elements. To reduce the size of the final data file, it was decided to aggregate the smallest units into "generic" units at the state level. Facilities aggregated into these generic units were all steam facilities smaller than 25 megawatts electric output and all nonsteam units smaller than 50 megawatts electric output (see Table A-1). These cutoff points were selected based primarily on two factors. First, the amount of information available on steam units of less than 25 megawatts is significantly less than that available on larger facilities. The cutoff for nonsteam units was set higher since these units are usually not as significant as steam units in terms of environmental impacts. Also, the relative amount of electricity generated from nonsteam units is lower because many of these units are used only as peaking plants (see Table A-2).

Utilities are required to forecast future electricity demand and to identify which additional facilities are needed to meet additional demand. They are also required to project the retirement of currently operational generating facilities. In most cases, specific unit-by-unit plans are available for a forecast period of about 10 years. These planning data are of significant value in attempting to project the facilities to be operated by the industry in future periods and are included in the unit inventory. Of course, much less information is available for projected facilities than for current ones.

Table A-1
OVERVIEW OF UNIT INVENTORY CONTENTS
(in numbers of units)

	Existing Units	
	Small[a]	Large
Steam	94	2027
Nonsteam	109	864
	New Units	
Steam	415	
Nonsteam	140	

[a] "Small" or "generic" units are less than 25 megawatts for steam and less than 50 megawatts for nonsteam.

A-2.2 Contents

Approximately 50 data elements are maintained for each generating unit in the unit inventory. There is space for additional elements to be added as a result of model operation, analysis, and so forth.

The unit inventory data elements have been organized into nine logical subgroups. Table A-3 presents the list of data elements included in the inventory within these subgroups. In addition, the notes and codelist references in Table A-3 document some of the conventions used in developing the inventory.[1] In Section A-3, information is presented on the individual data elements forming each subgroup in the unit inventory. Below, an overview of each subgroup is presented.

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[1] In addition, see codelists A through N, which appear at the end of this appendix. The codelists are taken from Reference 1.

Table A-2
OVERVIEW OF UNIT INVENTORY BY TOTAL CAPACITY
(in gigawatts)

	Existing Units	
	Small[a]	Large
Steam	7	446
Nonsteam	53	82
	New Units	
Steam	251	
Nonsteam	27	

[a] "Small" or "generic" units are less than 25 megawatts for steam and less than 50 megawatts for nonsteam.

Table A-3
LOGICAL ORGANIZATION OF THE UNIT INVENTORY

Item Identifier	Element	Units/ Codelist	Notes
	Location/Identification		
1	Unit sequence number		
2	ORIS plant code		
3	Unit code		
4	Multiplier		
5	FIPS location code (state/county)		a
6	FIPS owner state code		b
7	ORIS respondent code		
8	Dispatch region		b
	Unit Operation Characteristics		
9	Prime mover	Codelist A	
10	Technology code	Codelist B	
11	Heat rate	Btu/KWh	
12	Initial capacity	MW	
13	Current capacity (net penalties)	MW	
14	Design capacity factor	fraction	
15	Current capacity factor	fraction	
16	Estimated availability	fraction	
17	Generation, current year	GWh	
18	Boiler bottom	Codelist G	
19	Firing type	Codelist H	
20	Nonfuel variable O&M costs	mills/KWh	
	Unit Lifetime Data		
21	Year on-line		
22	Retirement year		
	Primary Fuel Data		
23	Fuel code	Codelist C	
24	Higher heat value	Btu/quantity	c
25	Sulfur content	percent	
26	Ash content	percent	
27	Delivered price	cents/MMBtu	
28	Quantity of fuel consumed	quantity	d
29	Fuel consumed at CF=1	quantity	d
	First Coal		
30	Btu fraction	fraction	
31	Higher heat value	Btu/pound	
32	Sulfur content	percent	
33	Ash content	percent	
34	Delivered price	cents/MMBtu	
35	Supply region	Codelist I	

Table A-3 (con't)

Item Identifier	Element	Units Codelist	Notes
	Second Coal		
36	Btu fraction	fraction	
37	Higher heat value	Btu/pound	
38	Sulfur content	percent	
39	Ash content	percent	
40	Delivered price	cents/MMBtu	
41	Supply region	Codelist I	
	Secondary Fuel Data		
42	Fuel code	Codelist C	
43	Higher heat value	Btu/quantity	c
44	Sulfur content	percent	
45	ASh content	percent	
46	Delivered price	cents/MMBtu	
47	Quantity of fuel consumed	quantity	d
	Regulatory Information		
48	SO2 regulatory category	Codelist J	
49	Initial SO2 standard	pounds/MMBtu	
50	New SO2 standard	pounds/MMBtu	b
51	SO2 compliance year		
52	TSP regulatory category	Codelist J	
53	Initial TSP standard	pounds/MMBtu	
54	New TSP standard	pounds/MMBtu	b
55	TSP compliance year		
56	NOx regulatory category	Codelist J	
57	Initial NOx standard	pounds/MMBtu	
58	New NOx standard	pounds/MMBtu	b
59	NOx compliance year		b
	Pollution Control Data		
60	SO2 control device	Codelist E	
61	SO2 removal efficiency	percent	
62	SO2 device gas bypass	fraction	b
63	SO2 emission rate	pounds/Mwhr	
64	NOx control device	Codelist F	
65	Secondary NOx device	Codelist F	
66	Tertiary NOx device	Codelist F	
67	NOx removal efficiency	percent	
68	NOx emission rate	pounds/Mwhr	
69	TSP control device	Codelist D	
70	TSP removal efficiency	percent	
71	TSP emission rate	pounds/Mwhr	
72	Total variable cost associated with pollution control		b

Table A-3 (con't)

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[a] Provided as a five-digit code sseee where ss is the state FIPS code and ccc is the county FIPS code.

[b] Not implemented.

[c] Differs by fuel type as follows:

Fuel	*Quantity Units*
Coal	pounds
Oil	gallons
Gas	cubic feet

[d] Differs by fuel type as follows:

Fuel	*Quantity Units*
Coal	1000 tons
Oil	1000 barrels
Gas	1000 Mcf

A-2.2.1 Location/Identification

This subgroup contains the unit identification and locational information. Units are identified by the associated plant name (as well as the plant code assigned by the Department of Energy, if applicable) and a unit code. Plants are located according to state and county using the FIPS coding scheme.

A-2.2.2 Unit Operation Characteristics

Unit operation characteristics describe both the type of unit (i.e., the prime mover) and the operating statistics for 1980, the base year. The latter information includes current net dependable capacity, 1980 generation, and 1980 capacity factor. Other characteristics include burner type and bottom type (for boilers). Additional data elements added for modeling purposes include initial capacity, design capacity factor, estimated availability, and nonfuel variable operating and maintenance (O&M) expense for the unit.

A-2.2.3 Unit Lifetime Data

Two data elements are included in this subgroup, year on-line and retirement year. As the retirement year is not announced for most plants, a system-generated retirement year based on a randomizing retirement date prior to 1990. This procedure is discussed in more detail in Section A-3.

A-2.2.4 Primary Fuel Data

The unit inventory contains data on either one or two separate fuels (primary and secondary) for each unit. The purpose of this capability is to properly account for the large number of dual-fired units operated by the utility industry. These units are usually gas-fired with oil backup or vice versa. The primary fuel is identified as the fuel that provided the greatest amount of total Btu of thermal input in 1980. For those units with three fuels, the least important fuel (as measured by total Btu value) is omitted. Information collected on the fuel includes heat value, fuel quality (sulfur and ash contents), delivered price, and quantity used. The fuel quality information reported here is based on quantity-weighted averages of data from individual fuel shipments received during 1980.

A-2.2.5 First Coal

For coal plants, detailed coal shipment data obtained from FPC Form 423 [2] were used to identify the source of coals consumed according to state and Bureau of Mines (BOM) district of origin. All coal shipments received at a plant from each state/BOM district are averaged together (quantity weighted), and data on the two most significant coals (in terms of total heating value of the coal received at the plant from each origin location) are provided in the unit inventory. Data included are the fraction of total Btu consumed at the plant from this coal, average quality, average delivered price, and supply region.

A-2.2.6 Second Coal

The data elements provided are identical to those of the "first" coal discussed above.

A-2.2.7 Secondary Fuel Data

The data elements provided are identical to those of the "primary" fuel discussed above.

A-2.2.8 Regulatory Information

Regulatory information is provided for total suspended particulates (TSP), sulfur dioxide (SO_2), and nitrogen oxides (NO_x).

A-2.2.9 Pollution Control Data

Information on pollution control facilities in place and on their operational performance is provided for all facilities designed to limit emissions of TSP, SO_2, or NO_x.

A-2.3 Development Approach

The approach taken in developing the unit inventory was to rely to the greatest extent possible on data available from public sources, especially files available in machine-readable form. As a result, the unit inventory is composed of information from many different sources.

A variety of processing techniques were required to format the available information from these sources into a single consistent data system. These techniques are described in more detail in Section A-3.

In many cases, one-to-one correspondence between different data sources could not be achieved. Among the reasons are that many of the data bases utilize slightly different definitions of the universe of respondents and that the types of information collected are different. One example is the attempt to combine data from Department of Energy's Generating Unit Reference File (GURF) [3] with data from the agency's FPC Form 67 data base [4]. The problem in this instance is that the GURF is oriented toward *generating units*, while the Form 67 data are oriented toward *boilers*. Because some plants have multiple boilers feeding single generators or vice versa, a certain amount of manipulation and judgement is required when attempting to combine these data.

Other data elements are simply not available from standard sources and, as a result, had to be calculated. Examples include heat rate and capacity factor. In some cases, the calculated values that resulted from combining data from various sources were unreasonable; when this occurred, judgments were made as to which of the input values should be considered to be the most accurate, and other dependent data values were adjusted accordingly. As mentioned above, the specifics of significant calculations and assumptions are discussed later in more detail.

Table A-4 identifies the primary source of data for each element in the unit inventory. As a result of the combination of divergent data sources, the actual data values in the inventory may not be identical with any of the individual data sources; on the other hand, the data values in the inventory should correspond most closely to those data sources in which there was the greatest confidence.

In general, when discrepancies were found, the following relative source priority was used:

1. FPC Form 4
2. FPC Form 423
3. Generating Unit Reference File
4. FPC Form 67.

A-2.4 Characteristics and Comparisons

As indicated above, the unit inventory covers both steam and nonsteam units. In addition, small units are treated as "generic" units and information is included, when possible, on announced new units. Table A-1 summarizes the contents of the unit inventory along these dimensions.

As Table A-1 shows, the unit inventory contains information on slightly more than 2000 large steam units and slightly fewer than 900 large nonsteam units (including hydroelectric, combustion turbine, and so forth). Small units, assigned by state and fuel type, are aggregated into 94 "generic" steam units and 109 "generic" nonsteam units. The only data included for new units in the unit inventory are for "large" units. These data cover more than 500 announced new units, more than three-fourths of them steam units.

Table A-2 presents the total capacity within each of the same categories as used in Table A-1. Table A-2 shows the importance of the "large" steam category in terms of the total industry capacity. Note that the "small" nonsteam category actually accounts for a significant quantity of generating capacity despite being represented in the unit inventory as a relatively small number of units. The reason is that the unit inventory contains a "multiplier," which is applied to each of the generic small units so that

Table A-4
PRIMARY SOURCES OF UNIT INVENTORY DATA

Item Identifier	Element	Source[a]
	Location/Identification	
1	Unit sequence number	*
2	ORIS plant code	GURF
3	Unit code	GURF
4	Multiplier (share owned)	*
5	FIPS location code (state/county)	GURF
6	FIPS owner state code	N/A
7	ORIS respondent code	GURF
8	Dispatch region	N/A
	Unit Operation Characteristics	
9	Prime owner	GURF
10	Technology code	URGE
11	Heat rate	C
12	Initial capacity	N/A
13	Current capacity (net penalties)	GURF
14	Design capacity factor	URGE
15	Current capacity factor	C
16	Estimated availability	URGE
17	Generation, current year	4, 67
18	Boiler bottom	67
19	Firing type	67
20	Nonfuel variable O&M costs	1
	Unit Lifetime Data	
21	Year on-line	GURF
22	Retirement year	GURF,URGE
	Primary Fuel Data	
23	Fuel code	423, 4
24	Highest heat value	423
25	Sulfur content	423
26	Ash content	423
27	Delivered price	423
28	Quantity of fuel consumed	423
29	Fuel consumed at CF=1	C
	First Coal	
30	Btu fraction	423
31	Higher heat value	423
32	Sulfur content	423
33	Ash content	423
34	Delivered price	423
35	Supply region	423

Table A-4 (con't)

Item Identifier	Element	Source
	Second Coal	
36	Btu fraction	423
37	Higher heat value	423
38	Sulfur content	423
39	Ash content	423
40	Delivered price	423
41	Supply region	423
	Secondary Fuel Data	
42	Fuel code	423, 4
43	Higher heat value	423
44	Sulfur content	423
45	Ash content	423
46	Delivered price	423
47	Quantity of fuel consumed	423
	Regulatory Information	
48	SO2 regulatory category	SS
49	Initial SO2 standard	SS
50	New SO2 standard	N/A
51	SO2 compliance year	N/A
52	TSP regulatory category	SS
53	Initial TSP standard	SS
54	New TSP standard	N/A
55	TSP compliance year	N/A
56	NOx regulatory category	SS
57	Initial NOx standard	SS
58	New NOx standard	N/A
59	NOx compliance year	N/A
	Pollution Control Data	
60	SO2 control device	FGD
61	SO2 removal efficiency	FGD
62	SO2 device gas bypass	N/A
63	SO2 emission rate	C
64	NOx control device	NOx
65	Secondary NOx device	NOx
66	Tertiary NOx device	NOx
67	NOx removal efficiency	NOx
68	NOx emissions rate	C
69	TSP control device	67, URGE
70	TSP removal efficiency	67
71	TSP emission rate	C
72	Total variable cost associated with pollution control	N/A

Table A-4 (con't)

Source Code	*Meaning*
*	Assigned by the unit inventory system
GURF	Generating Unit Reference File, 1981 [3]
423	FPC Form 423, 1980 [8]
4	FPC Form 4, 1980 [5]
67	FPC Form 67, 1979 [6]
FGD	EPA Utility FGD Survey, 1981 [14,15]
NOx	NO_x Control Review [16]
1	FPC Form 1, 1979, by plant type [10]
SS	Special study (e.g., [7, 12-16]
C	Calculated by the unit inventory system
URGE	Specified by URGE AUSM researchers

capacity totals are properly accounted for. This multiplier is intended to approximate the total number of small units being averaged together. For example, if there are 200 megawatts of oil-fired combustion turbines of less than 50 megawatts capacity per unit in a state, they are represented collectively as *one* unit in the unit inventory with a capacity of 25 megawatts and a multiplier of 8 (i.e., $\frac{200MW\ total}{25MW\ perunit} =$ 8 units). In Table A-2, the reported capacity is computed as the multiplier times the unit's net dependable capacity.

The figures in Tables A-1 and A-2 demonstrate the need to include all types of generating units when characterizing the industry. For example, many other data bases include only steam units and thus miss a substantial portion of the total facilities available to the industry.

Much of the information used in the unit inventory was based on utility submissions on FPC Form 4 (now revised as EIA Form 759) [5]. Table A-5 presents a comparison between summary statistics for all generating units from the 1980 Form 4 file and similar statistics for all generating units from the unit inventory. For the reasons discussed above, it would be unreasonable to expect exact one-to-one

Table A-5
COMPARISON OF UNIT INVENTORY SUMMARY STATISTICS WITH FPC FORM 4

	Unit Inventory	FPC Form 4	Unit Inventory as Percent of Form 4
Coal (million tons)	567	569	99.6
Oil (million barrels)	422	420	100.5
Gas (trillion cubic feet)	3.7	3.7	100.0
Generation (terawatt hours)	2254	2292	98.3
Capacity (gigawatts)	588	607	96.9

correspondence between these data bases. However, the aggregate figures are quite close.

A comparison of the quantity of coal deliveries accounted for in the unit inventory's "first" and "second" coal fields is presented in Table A-6. Aggregating over all coal shipments, more than 83 percent of the coal receipts at all plants are from the primary state/BOM district supplying the plant, while an

Table A-6
UTILITY COAL RECEIPTS FOR 1980 BY STATE/BOM REGION OF ORIGIN

State/BOM Region of Origin	Number of Shipments	Quantity (million tons)	Quantity (percent of total)
Primary	408	496.7	83.6
Secondary	231	74.1	12.5
Other	255	23.5	4.0
Total	894	594.3	100.0

additional 12.5 percent are from the secondary state/BOM district source.

A-3 Unit Inventory Implementation

A-3.1 Programming Methodology

Because the information from the unit inventory comes from so many sources, a flexible method of developing the actual inventory was needed. As some of the input files are quite large (for example, the fuel quality data contains information on approximately 60,000 individual fuel deliveries to power plants in 1980), it was also necessary that the method or methods selected be efficient. The wide range of types of data processing required to create the unit inventory dictated the use of a combination of programming languages and methodologies.

Initial data reduction of the larger files was performed by a series of PL/I programs. These files were reduced to one record per plant (or unit if a unit-level file). The reduced files were then converted to an internal format using the Statistical Analysis System (SAS). These internal SAS files were combined and manipulated using a series of SAS programs. Examples of the processing include the calculation of default state average fuel quality data and the assignment of technology codes. The result of these manipulations was a final unit inventory in SAS format. The final processing step converted the unit inventory data bases into a transferable, machine-independent format. The transferable form of the unit inventory is referred to as the "external" format because it can be sent to other installations, typically on magnetic tape.

A-3.2 Format of the External Unit Inventory

To permit the unit inventory to be made widely available, a machine-independent external format was developed for the distribution file. Potential users of the unit inventory are provided with the inventory in this standard format. Use of the concept of "generic" small plants means that the resulting file is small enough to warrant complete replacement when a new version is developed. Therefore, updates are accommodated by replacing the entire file rather than by updating single elements. The effort involved in developing machine-independent software to permit item-by-item updating is simply not justified by the reduced size of the file.

Table A-7 presents the external unit inventory format. Since it is in card image, it can be used on almost all available computer systems. The formats of numeric data are designed to be accessible to any mathematically oriented language, including FORTRAN and PL/I. While the "internal" unit inventory is maintained in the form of a binary SAS format, it is also relatively easy for a SAS user to "reload" the external unit inventory into a SAS form for internal use.

A-3.3 Special Implementation Features

In this section, special features of the unit inventory implementation are discussed that may be of interest to those users concerned with the more detailed aspects of inventory implementation. Following a general discussion of how unit- and plant-level data were combined in the unit inventory, notes are provided for selected individual data subgroups or elements.

In general, information on the universe of generating units was obtained from the DOE GURF [3], discussed above. The other major source of unit-specific information was the 1979 FPC Form 67 data base [6]. The 1979 Form 67 file was used instead of the 1980 file because the latter was not available at the time the unit inventory was developed. It is expected that during 1983 the unit inventory will be revised using 1980 Form 67 data. Form 67 provides information on steam boilers at plants with a total steam generating capacity above 25 megawatts. In those cases where units identified in the GURF did not correspond directly to boilers reported on Form 67, attempts were made to aggregate GURF data to the boiler level. In order to identify such cases, "dummy" unit numbers of 500 or higher were assigned to the "units" created for the inventory.

Operating characteristics such as total generation and total fuels consumed for generation were obtained from FPC Form 4 [5]. Form 4 is a monthly data base, but for purposes of the unit inventory development, the monthly data for 1980 were aggregated into annual totals. Form 4 data are reported by plant and by prime mover. Thus, a plant having both steam and nonsteam units would have data in both

Table A-7
PHYSICAL ORGANIZATION OF THE UNIT INVENTORY

Card	Columns	Format	Name	Logical Item Identifier
1	1-5	I5	SEQNO2	1
	6-7	I2	"01"	N/A
	8-12	I5	ORISPL	2
	13-16	A4	UCODE	3
	17-23	F7.2	MULT	4
	24-28	I5	FIPSLOC	5
	29-30	I2	OWNST	6
	31-35	I5	ORISR	7
	36-75	A40	PNAME	
2	1-5	I5	SEQNO2	1
	6-7	I2	"02"	N/A
	8-9	I2	PRIME	9
	10-11	I2	TCODE	10
	12-17	I6	HTRATE	11
	18-22	I5	NETDC	12
	23-27	I5	NETDC	13
	28-31	F4.2	DCAPAC	14
	32-35	F4.2	CFACT	15
	36-39	F4.2	AVAIL	16
	40-47	F8.1	GENER	17
	48-49	I2	BNUM	18
	50-51	I2	FNUM	19
	52-56	F5.1	VOM	2
	57-60	I4	YRONL	21
	61-64	I4	RETDT	22
3	1-5	I5	SEQNO2	1
	6-7	I2	"03"	N/A
	8-9	I2	FUEL1	23
	10-15	I6	HEAT1	24
	16-19	F4.1	SULF1	25
	20-23	F4.1	ASH1	26
	24-29	F6.1	FCOST1	27
	30-36	F7.1	QUAN1	28
	37-44	F8.1	QCF1	29
	45-46	I2	FUEL2	42
	47-52	I6	HEAT2	43
	53-56	F4.1	SULF2	44
	57-60	F4.1	ASH2	45
	61-66	F6.1	FCOST2	46
	67-73	F7.1	QUAN2	47

Table A-7 (con't)

Card	Columns	Forman	Name	Logical Item Identifier
4	1-5	I5	SEQNO2	1
	6-7	I2	"04"	N/A
	8-11	F4.2	HFRAC	30
	12-17	I6	BTU	31
	18-21	F4.1	SULF	32
	22-25	F4.1	ASH	33
	26-31	F6.1	COST	34
	32-33	I2	ORIGIN	35
	34-37	F4.2	SHFRAC	36
	38-43	I6	SBTU	37
	44-47	F4.1	SSULF	38
	48-51	F4.1	SASH	39
	52-57	F6.1	SCOST	40
	58-59	I2	SORIGIN	41
5	1-5	I5	SEQNO	1
	6-7	I2	"05"	N/A
	8	I1	SO2CAT	48
	9-12	F4.1	SO2SIP	49
	13-16	F4.1	N/A	50
	17-20	I4	N/A	51
	21	I1	TSPCAT	52
	22-25	F4.1	TSPSIP	53
	26-29	F4.1	N/A	54
	30-33	I4	N/A	55
	34	I1	NOXCAT	56
	35-38	F4.1	NOXSIP	57
	39-42	F4.1	N/A	58
	43-46	I4	N/A	59
6	1-5	I5	SEQNO	1
	6-7	I2	"06"	N/A
	8-9	I2	SO2CTL	60
	10-14	F5.2	SO2EFF	61
	15-18	F4.2	N/A	62
	19-23	F5.1	NO2RTE	63
	24-25	I2	NOXCTL	64
	26-27	I2	NOXCLT2	65
	28-29	I2	NOXCLT3	66
	30-34	F5.2	NOXEFF	67
	35-39	F5.1	NOXRTE	68
	40-41	I2	TSPCTL	69
	42-46	F5.2	TSPEFF	70
	47-51	F5.1	TSPRTE	71
	52-58	F7.5	N/A	72

of these categories.

Unit-specific data for 1980 were estimated by applying 1979 unit shares computed from 1979 Form 67 data to 1980 totals from Form 4. For those cases where another unit was added in 1980, the difference in operating rates between 1980 Form 4 totals and 1979 Form 4 totals was assigned to the new unit.

Fuel quality data were obtained from FPC Form 423. For units with no reported Form 423 information, state average data obtained from Form 423 were used. The state average values used in the unit inventory are listed in Volume I of *Estimates of Sulfur Oxide Emissions from the Electric Utility Industry* [7].

A-3.3.1 **Location/Identification**

A-3.3.1.1 **Unit Sequence Number**. The records in the unit inventory were sorted by FIPS state code and ORIS plant code. The unit sequence number was then assigned as a unique code. The sequence number is a five-digit code, the first two digits being the separate state Federal Information Processing Standards (FIPS) code and the last three digits being assigned sequentially within each state (always beginning with 001).

A-3.3.1.2 **ORIS Plant Code**. The DOE code was used for units in all plants for which a code was available. The "generic" small units (each of which is treated as a single plant), new units located at existing plants without a preassigned code, and some existing plants did not have an ORIS code and had to be assigned one. Since DOE ORIS plant codes are four digits, fabricated ORIS codes use five digits to avoid confusion.

For units at existing plants without assigned DOE ORIS codes, new plant codes were assigned sequentially (starting with Alabama and moving alphabetically through the states), beginning with 10001. For units at new plants without assigned DOE codes, codes were assigned sequentially beginning with 20001. For the generic small units, codes were assigned sequentially beginning with 30001.

A-3.3.1.3 **Unit Code**. As indicated above, generating unit codes expressed as numbers of 500 or above were assigned in those cases in which Form 67 and GURF data did not indicate a one-to-one correspondence between generating units and boilers. In addition, plants for which conversion to coal has been announced were entered twice in the unit inventory. The unit first appears with its current fuel, using as a plant retirement date the date on which the unit is projected to go out of service to begin conversion. The unit is also reported with the new fuel, with the on-line date set to the year in which the plant is expected to reenter service. The unit code for this second occurrence is always preceded by the letter "C."

A-3.3.1.4 **Multiplier**. The multiplier is used to indicate the number of identical small "generic" units assumed to exist. For large units, the value of this field is 1.0.

A-3.3.1.5 **FIPS Location Code**. This field contains state and county codes as specified by the Federal Information Processing Standards. The field is five digits, with the first two digits being the state code and the last three digits being the county code. If the county code is unknown, it is coded as zero.

A-3.3.1.6 **FIPS Owner State Code**. This field is reserved for future expansion.

A-3.3.1.7 **ORIS Respondent Code**. This field contains a DOE-assigned code that identifies the plant owner or operator responsible for submission of reports concerning plant operations to DOE. It is termed "respondent" code because it identifies the entity that responds to DOE data requests.

A-3.3.1.8 **Dispatch Region**. This field is reserved for future expansion.

A-3.3.2 Unit Operation Characteristics

A-3.3.2.1 **Prime Mover**. This is the method by which the unit generates electricity.

A-3.3.2.2 **Technology Code**. This code was specified by other AUSM researchers and is based on prime mover and fuel characteristics.

A-3.3.2.3 **Heat Rate**. Heat rate values were derived based on fuel quality (Btu per unit of fuel) from FPC Form 423 [8] and operational data (total generation and quantity of fuel used from Form 4 [5]). Adjustments were made when necessary to ensure that estimated heat rates fell within a "reasonable" range. The lowest reasonable heat rate was assumed to be 8700 Btu per kilowatt hour for steam units and 11,000 Btu per kilowatt hour for nonsteam units. The highest reasonable heat rate was assumed to be 25,000 Btu per kilowatt hour for all units. If a calculated heat rate fell outside this specified range, it was set to either the appropriate lower bound (8700 or 11,000) or to the appropriate upper bound (24,000). The quantity of generation was also adjusted so that the relationship between revised heat rate, fuel used, and generation was arithmetically correct.

A-3.3.2.4 **Initial Capacity**. This field is reserved for modeling use and is set equal to the current capacity in the unit inventory.

A-3.3.2.5 **Current Capacity**. This field was obtained from the "net dependable capacity" field on the GURF. It was sometimes adjusted to ensure that calculated capacity factors were feasible (see Section A-3.3.2.7, below). This value is net of the effects of pollution control capacity penalties.

A-3.3.2.6 **Design Capacity Factor**. These values were obtained from a table lookup based on technology code. The values used here were provided by the University of Illinois [9] and are listed in Table A-8.

A-3.3.2.7 **Current Capacity Factor**. The values in this field were calculated from generation, current capacity, and the number of hours per year. For cases in which the calculated capacity factor exceeded 1.0, the calculated value was replaced by 0.87 for steam and hydroelectric units and by 0.40 for all other units. In addition, the current capacity field was adjusted so that the relationships between the revised capacity factor, current capacity, and number of hours per year were arithmetically correct.

A-3.3.2.8 **Estimated Availability**. These values were obtained from a table lookup based on technology code. The values used were provided by AUSM researchers [9]; they are listed in Table A-8.

Table A-8
AVAILABILITY AND DESIGN CAPACITY FACTORS INCLUDED IN THE UNIT INVENTORY

Technology Code	Availability	Design Capacity Factor
1	.891	.300
2	.891	.300
3	.871	.300
4	.960	.300
5	.802	.802
6	.802	.802
7	.802	.802
8	.802	.802
9	.929	.929
10	.929	.929
11	.846	.846
12	.769	.769
13	.811	.811
14	.754	.754
15	.709	.709
16	.682	.682
17	.755	.755
18	.755	.755
19	.900	.900
20	.632	.632
21		
22	.906	.906
23		

Source: Reference 9.

A-3.3.2.9 **Firing Type**. When more than one firing type was reported on Form 67, the primary firing type was used. In addition, contacts were made with the individual utilities to obtain firing type information for some large units for which no firing type was reported on Form 67.

A-3.3.2.10 **Nonfuel Variable O&M Costs**. These values were obtained from aggregated FPC Form 1 submissions [10]. They include the costs of all nonfuel operation and maintenance expenses associated with power generation, as reported by the utilities in conformance with procedures of the Federal Energy Regulatory Commission (FERC). Table A-9 lists the values used.

Table A-9
VARIABLE O&M COSTS INCLUDED IN THE UNIT INVENTORY
(in mills per kilowatt hour)

Plant Type	Variable O&M Costs
Coal	3.34
Other fossil steam	1.80
Geothermal and hydroelectric	20.50
Nuclear steam	.35
Other	9.23

Source: Reference 10.

A-3.3.3 Unit Lifetime Data

A-3.3.3.1 **Year On-Line**. For all generic small units, the year on-line was entered as 1955 in the unit inventory.

A-3.3.3.2 **Retirement Year**. For units with a reported retirement year in GURF, the reported values were used. For other units, an assumed retirement date was computed based on the design plant lifetime values reported in Table A-10. If the computed retirement date using this method was earlier than 1990, it was randomly adjusted to be a value ranging from 1990 to 2000 using a uniform pseudo-random number distribution.

For units converting to coal, the assumed retirement date was 20 years from the year the unit is expected to reenter service.

A-3.3.4 Primary and Secondary Fuel Data

Primary fuel codes were recorded in the unit inventory based on the fuel (among coal, oil, and gas) supplying the largest quantity (in Btu) of total heat used for generation. Quality data for fossil-fired

Table A-10
DESIGN LIFE BY PLANT TYPE
(in years)

Plant Type	Default Lifetime
Coal	45
Other steam	35
Hydroelectric	60
Other units	35

plants that were not reported on FPC Form 423 were derived from 1980 statewide average statistics.

Fuel quality data (heat value, sulfur content, and ash content) were reported only for fossil fuels.

A-3.3.4.1 **Delivered Price.** The price for nuclear fuel was assumed to be 72 cents per million Btu (average 1980 costs from Department of Energy statistics) [2] for all nuclear plants. The price for water used by hydroelectric and geothermal units was assumed to be zero because, essentially, the entire variable cost of generation for these units is nonfuel O&M.

A-3.3.4.2 **Fuel Consumed at CF=1.** This field is calculated as the quantity of the primary fuel that would be required if the plant operated at a capacity factor of 1.0 for the entire year, i.e., 24 hours a day for 365 days.

A-3.3.5 Regulatory Information

These data were gathered from a variety of sources, including Form 67 and various special studies and reviews. Examples of special studies are contacts made with individual utility plants.[2] Information from EPA headquarters and regional office reviews of the preliminary regulatory standards were also included in the values reported in the unit inventory. Nevertheless, the data on SO_2, TSP, and NO_x regulations were not available for every unit. Emission standards for units for which no data were available, or for units which are unregulated, were reported as zero. The reason for reporting both types of units as zero is because no information is available to enable these two categories to be separated.

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[2] Other examples are found in Reference 7 and References 11-16.

The following fields are reserved for modeling purposes and are reported as zero in the unit inventory: (1) new SO_2 standard, (2) SO_2 compliance year, (3) new TSP standard, (4) TSP compliance year, (5) new NO_x standard, and (6) NO_x compliance year.

A-3.3.6 Pollution Control Data

A-3.3.6.1 **SO_2 Gas Device Bypass**. This field is reserved for modeling purposes and is reported as zero in the unit inventory.

A-3.3.6.2 **TSP Control Device**. No information was available on whether electrostatic precipitators (ESPs) were cold- or hot-sided. As a result, based on specifications of AUSM researchers [17], the unit inventory assumes that ESPs associated with units burning fuel with a sulfur content of less than 1.0 percent (by weight) are hot-sided and that all others are cold-sided.

A-3.3.6.3 **TSP Removal Efficiency**. As indicated in Table A-4, the values for this field were obtained from FPC Form 67. For those cases in which reported TSP removal efficiency was greater than 99.95 percent, the unit inventory value was reported as 99.95.

A-3.3.6.4 **TSP Emission Rate**. TSP emission rates were computed from simplified AP-42 coefficients by fuel type. Uncontrolled emission rates were assumed to be 7 pounds per million Btu for coal and 0.17 pounds per million Btu for oil. TSP emissions were not computed for other fuels. Coal-fired units were assumed to control at least 65 percent of uncontrolled TSP emissions to meet capacity requirements not included in the initial TSP standard field. If a unit had a reported TSP emission standard, it was assumed that the unit was in compliance with that standard.

A-3.3.6.5 Total Variable Cost Associated with Pollution Control. This field is reserved for modeling purposes and is reported as zero in the unit inventory.

A-4 Codelists

The following pages display lists of the code definitions used in the AUSM.

Codelist A
PRIME MOVER TYPE

Code	*Type*
0	No data
1	Fossil steam (boiler)
2	Geothermal
3	Conventional hydroelectric
4	Pumped storage hydroelectric
5	Nuclear steam
6	Internal combustion
7	Combined cycle
8	Combustion turbine
9	Exotic

Codelist B
PLANT TECHNOLOGY TYPES

Code	*Type*
	PEAKING PLANTS
1	Gas combustion turbine
2	Distillate oil combustion turbine
3	Residual oil combustion turbine
4	Hydro-pumped storage (underground)
	INTERMEDIATE AND CYCLING PLANTS
5	Conventional gas steam
6	Conventional distillate oil steam
7	Conventional residual steam
8	Solvent refined coal
9	Gas combined cycle
10	Distillate oil combined cycle
11	Residual oil combined cycle
12	Pressurized fluidized bed-combined cycle
13	Gasification-combined cycle
14	Gasifier - gas-fired boiler
	BASE LOAD PLANTS
15	Coal steam power plant (uncontrolled)
16	Light water reactor (pressurized or boiling water)
17	Bituminous atmospheric fluidized bed
18	Sub-bituminous atmospheric fluidized bed

Codelist B (con't)

Code	*Type*
	RENEWABLES AND OTHER
19	Hydroelectric dam
20	Magnetohydrodynamic combined cycle
21	Geothermal (brine solution)
22	Dispersed fuel cells
23	Solar central receiver

Codelist C
FUEL CODE

Code	*Fuel Type*
0	No data
1	Coal
2	Residual oil
3	Distillate oil
4	Natural gas
5	Gasoline
6	Nuclear fuel
7	Other

Codelist D
PARTICULATE CONTROL TECHNOLOGY CODE

Code	*Type*
0	No data
1	Mechanical collector
2	Cold-side electrostatic precipitator (ESP)
3	Hot-side electrostatic precipitator (ESP)
4	Combination mechanical/ESP
5	Baghouse

Codelist E
SO_2 CONTROL TECHNOLOGY CODE

Code	*Type*
0	No data
1	Wet limestone scrubber
2	Dry limestone scrubber
3	Magnesium oxide

Codelist F
NO_x CONTROL TECHNOLOGY CODE

Code	*Type*
0	No data
1	Burners out of service (BOOS)
2	Derating
3	Fuel switching
4	Flue gas recirculation
5	Low NOx burner
6	Overfire air
7	Off-stoichiometric firing
8	Reduced air preheat
9	Water injection
10	Steam injection
11	Ammonia injection
12	Selective catalytic reduction

Codelist G
BOTTOM TYPE

Code	*Type*
0	No data
1	Wet
2	Dry

Codelist H
FIRING TYPE*

Code	*Type*
0	No data
1	Wall
2	Opposed
3	Tangential
4	Spreader stoker
5	Cyclone

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*Primary firing type if more than one type coded.

Codelist I
FIPS STATE LIST

Code	*State*	*Ordinal*
1	Alabama	1
4	Arizona	2
5	Arkansas	3
6	California	4
8	Colorado	5
9	Connecticut	6
10	Delaware	7
12	Florida	8
13	Georgia	9
16	Idaho	10
17	Illinois	11
18	Indiana	12
19	Iowa	13
20	Kansas	14
21	Kentucky	15
22	Louisiana	16
23	Maine	17
24	Maryland	18
25	Massachusetts	19
26	Michigan	20
27	Minnesota	21
28	Mississippi	22
29	Missouri	23
30	Montana	24

Codelist I (con't)

Code	*State*	*Ordinal*
31	Nebraska	25
32	Nevada	26
33	New Hampshire	27
34	New Jersey	28
35	New Mexico	29
36	New York	30
37	North Carolina	31
38	North Dakota	32
39	Ohio	33
40	Oklahoma	34
41	Oregon	35
42	Pennsylvania	36
44	Rhode Island	37
45	South Carolina	38
46	South Dakota	39
47	Tennessee	40
48	Texas	41
49	Utah	42
50	Vermont	43
51	Virginia	44
53	Washington	45
54	West Virginia	46
55	Wisconsin	47
56	Wyoming	48

Codelist J
COAL SUPPLY REGIONS

Code	*State District*	*BOM District of Origin Number*
1	Pennsylvania-East	1
2	Pennsylvania-West	2
3	Maryland	1
4	West Virginia-East	1
5	West Virginia-North	3
6	West Virginia-Panhandle	6
7	West Virginia-Southeast	7
8	West Virginia-Southwest	8
9	Ohio	4
10	Virginia-East	7
11	Virginia-West	8
12	Kentucky-East	8
13	Kentucky-West	9
14	Tennessee-North	8
15	Tennessee-South	13
16	Illinois	10
17	Indiana	11
18	Iowa	12
19	Alabama	13
20	Arkansas	14
21	Oklahoma-East	14
22	Oklahoma-West	15
23	Kansas	15
24	Missouri	15

Codelist J (con't)

Code	*State District*	*BOM District of Origin Number*
25	Texas	15
26	Colorado-North	16
27	Colorado-South	17
28	New Mexico-Northeast	17
29	New Mexico-West	18
30	Arizona	18
31	Wyoming	19
32	Utah	20
33	North Dakota	21
34	Montana	22
35	Washington State	23

Codelist K
SULFUR CONTENT CATEGORIES

AUSM Categories

Code	*Sulfur Content**
1	[0, .65)
2	[.65, .85)
3	[.85,1.25)
4	[1.25,1.55)
5	[1.55,2.05)
6	[2.05,2.55)
7	[2.55,3.05)
8	[3.05,4.05)
9	[4.05,6.05)
10	[6.05,8.05)
11	[8.05,)

EIA Categories

Code	*Sulfur Content**
1	[0, .85)
2	[.85,1.15)
3	[1.15,1.35)
4	[1.35,1.65)
5	[1.65,1.85)
6	[1.85,3.35)
7	[3.35,5.00)
8	[5.00,)

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*Pounds of SO_2/MMBtu.

Codelist L
REGULATORY CATEGORIES

Code	*Category*
1	SIP
2	NSPS
3	(R)NSPS

Codelist M
LEVELS OF COAL PREPARATION

Code	*Topsizes*	*Midsizes*	*Finesizes*
1	Drying (optional)	Drying (optional)	Drying (optional)
2	Heavy medium cyclone	No cleaning	No cleaning
3	Heavy medium vessel	Heavy medium cyclone; drying (optional)	No cleaning
4	Heavy medium vessel	Heavy medium cyclone; drying (optional)	Hydrocyclone drying

Codelist N
HIGHER HEATING VALUE CATEGORIES

AUSM Categories			*EIA Categories*		
Code	***HHV Range****	***Description***	***Code***	***HHV Range****	***Description***
1	**(21.0,)**	**Bituminous**	**1**	**[26,)**	**Bituminous**
2	**(16.6,21.0]**	**Sub-bituminous**	**2**	**[23,26)**	**Bituminous**
3	**[0,16.6]**	**Lignite**	**3**	**[20,23)**	**Bituminous**
			4	**[15,20)**	**Sub-bituminous**
			5	**[0,15)**	**Lignite**

***Categories defined here in terms of MMBtu/ton (moist mineral-matter-free basis); actual data for individual codes are expressed in MMBtu/lb (as-received basis).**

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APPENDIX B. THE COAL RESERVES DATA BASE

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B.1 Introduction

B.1.1 Background

Although there is disagreement about the extent of increase in the role of coal as a source of energy in the future, all indications point to greater usage. While current projections of coal use in the 1990s are lower than those estimated immediately after the 1973 oil embargo, the large coal resource base in the United States makes coal an important part of the national energy picture for the foreseeable future.

The major reason for expecting significantly increased coal use is the large differential in cost between coal and the competing fuels, oil and natural gas. Although coal use has some significant disadvantages, such as greater environmental cost and more difficult and expensive handling and shipping requirements, the interfuel cost differential is now larger than at any previous time. This allows increased opportunities for ameliorating environmental costs without endangering the position of coal as a competitive alternative for additional applications.

Despite its cost advantages, a prosperous future for coal is not completely assured. Among the reasons are increased coal-mining costs due to government regulations, union procedures and safety regulations, possible renewed competition from oil and natural gas, the decrease in demand for metallurgical coal by the steel industry and the reduction in the growth of demand for electricity. With regard to regulatory requirements, for example, a coal strip-mining operation in West Virginia might have to go through as many as 100 regulatory steps before starting operations. While coal use in electricity generation has gained as costs and questions about nuclear energy have increased, these gains have not been great enough to offset the effects of the conservation practiced by electricity users, which has caused a significant decline in electricity demand growth.

Knowledge of coal reserves and resource information, and of the limitations of this information, are essential to the understanding of the coal industry in the United States. Future coal growth areas will be determined by the ability to mine coals and provide them to users at competitive delivered prices. Market dynamics make it impossible to forecast the "winners" over the long term among competing coals, at least in certain markets. For example, the use of coal in states such as Texas depends on the interaction of a number of factors. Essentially, Texas can convert from gas to coal in its power plants either by importing low-sulfur coal from Montana and Wyoming or by using in-state lignite reserves.

B-1.2 Purpose and Scope

This appendix provides information on the coal reserve and resource data developed by E.H. Pechan & Associates, Inc., over the past year. The data base was developed for the Advanced Utility Simulation Model.

This appendix examines and analyzes both the Department of Energy's (DOE) demonstrated reserve base (DRB) information and resource information from the Bureau of Mines (BOM). The analysis categorizes these data into coal (1) "DRB reserves" and (2) "economic reserves" or "reserves." The former designation is equivalent to DOE's DRB. The latter includes additional coal resources that are economically recoverable under current conditions but that have a resource assurance lower than that of the DOE-type "DRB reserves." The appendix also addresses the reliability of the data bases as they now exist. Finally, it documents the coal resource data files as developed for the AUSM.

B-1.3 Summary of Findings

Even using the narrow DRB reserves definition for available coal, the United States possesses enormous quantities of such coal. Assuming 50 percent recoverability, the most limited reserve base would permit more than 200 years of production at current levels.

Again using the DRB reserves definition, low-sulfur coals (defined as those able to meet the 1971 utility New Source Performance Standard) comprise almost 50 percent of total national reserves.

Using the economic reserves definition of available coal increases years of potential production by almost 75 percent. Even this definition, however, excludes vast additional quantities of coal that either (1) are hypothesized but not known to exist or (2) cannot be recovered profitably under current market conditions.

All of the major coal projection/cost models that were examined used extremely narrow definitions of coal reserves, even for projections made for 30 or more years into the future. Thus, it is likely that long-term "depletion" effects projected by the models are artifacts caused by use of improper data.

B-2 Coal Reserves and Resources Analysis

B-2.1 Defining the Limits of Resources and Reserves

The term "resources" covers the broadest spectrum of potential coal available for mining. It includes the tonnage of coal available with no regard to recoverability. Coal "reserves," on the other hand, are defined by the user and are limited to specific subsets of resources. These subsets are selected based on the dual criteria of resource quality (an economic recoverability criterion) and resource assurance (essentially the likelihood that the mineral actually exists).

The most commonly used definition of reserves is that from the Department of Energy's Demonstrated Reserve Base [1,2], called DRB reserves. Coal resources are identified as DRB reserves using two criteria, both of which must be met. These criteria are (1) economic recoverability and (2) resource assurance.

The economic criterion used in the DRB definition is designed to include those resources that can be recovered profitably under current economic conditions with the use of existing technologies. Such an assumption is considered to be extremely conservative for a depletable resource such as coal, because lower grade resources usually become "economical" as higher grade resources are used up due to increased real prices for increasingly scarce materials.

The resource assurance criterion in the DRB is based on a classification of reserves into two broad classes and, within the highest assurance class, three groups. The broad resource classes are hypothetical and identified. Hypothetical resources are rough estimates of quantities of resources contained in likely mineral formation. These estimates may be based on geological similarity of the region in question to other known coal-bearing areas, extension of identified coal-bearing areas, and so forth. Since the higher assurance identified resources are themselves so vast, little attention has been focused on the hypothetical coal resources. For other fuels, however, resource estimates used for analytical forecasting models often include resources having assurances even less than that of the hypothetical reserve category for coal. Fuels for which this is true include both oil and natural gas.

Hypothetical resources are not considered in a quantitative sense here. Instead, the focus is on the three classes of identified resources: measured, indicated, and inferred. These categorizations are based on measurements obtained by core samplings and on assumptions of bed continuity between samples. The particular category is based primarily on the density of the underlying physical measurements, i.e., the physical distance between the core samples. The DRB includes the classes "measured" and "indicated," which are only a limited portion of coal resources. These two categories include a belt of coal that is assumed to lie less than three-quarters of a mile from an outcrop or measurement. The third category, "inferred," includes coal extending beyond the indicated category out to a two and one-quarter mile belt. The "reserves" estimates used in this report include the inferred resources.

The DRB also includes coal in seams that are now being mined, no matter what the original resource assurance and/or economic criterion classification was. For example, Alabama bituminous coal in the Mary Lee coal bed is currently being mined but is at 2000 to 3000 feet rather than at the 1000-foot maximum depth considered "economical" in the DRB.

The result of the assumptions made in the development of the DRB assessment is a total DRB reserve estimate of slightly less than 500 billion tons of coal. These figures are shown by state in Table B-1. While 500 billion is a relatively large amount compared with current levels of production of approximtely 800 million tons per year, it is important to realize that these figures are total "in-place" coals and thus do not account for the fact that all of the in-place coal is never recovered. Estimates of the recovery

Table B-1
STATE AND NATIONAL DEMONSTRATED RESERVE BASE QUANTITIES
(in millions of tons)

State	Quantity
Alabama	5,000
Alaska	6,154
Arizona	410
Arkansas	411
Colorado	17,281
Georgia	4
Idaho	4
Illinois	67,606
Indiana	10,586
Iowa	2,198
Kansas	994
Kentucky	34,002
Maryland	822
Michigan	128
Missouri	6,069
Montana	120,428
New Mexico	4,521
North Carolina	11
Ohio	1,638
Oklahoma	1,638
Oregon	17
Pennsylvania	30,281
South Dakota	366
Tennessee	984
Texas	12,660
Utah	6,478
Virginia	3,471
Washington	1,481
West Virginia	39,776
Wyoming	69,924
United States	472,714

ratio range from somewhat less than 50 percent to almost 100 percent. The lower recovery ratios are associated with conventional deep-mining operations and with reserve blocks that may be constrained by being partially located under towns, streams, and so forth. The higher ratios are associated with large, thick seam strip-mining operations. The DRB report suggests that appropriate *average* recoverability figures for DRB reserves are 50 percent for deep coal and 90 percent for surface coal.

The reserves estimate we have derived, 780 billion tons, is substantially higher than the DRB reserves. The 500 billion ton DRB reserve figure and our 780 billion ton figure, however, are small compared with the total estimated United States coal *resources* of almost 4 trillion tons, a figure that includes hypothetical resources. The coal resource figures used by DOE and most other investigators for analytical purposes use much narrower definitions of recoverable resources for coal than are used for oil and natural gas. Estimates of liquid and gaseous fuel resources are usually based on some concept of total ultimately recoverable reserves that include substantial quantities from geological formations in which the presence of oil or gas has not been demonstrated. An equivalent type of estimate for coal would probably result in a resource estimate of well over 1.5 trillion tons, including only those coal resources that can be quantitatively estimated in some manner (the identified resources).

B-2.2 Assessing Coal in Place

Characterization of in-place resources is an ongoing process. The 1980 DOE DRB report [2] lists the progress of each state's attempt to characterize its coal by sulfur content and heating value. At this time, data from these studies are not available. Since DOE no longer estimates DRB coal quantities by quality category, one of the tasks we performed was the allocation of coal reserves by sulfur and heat content. This type of estimation assumes a continuance of the coal beds and similar characteristics within those beds. Section B-5 describes the methodology used to categorize the reserve data. In essence, the method involves using a statistical technique to assign the sulfur content of "best estimate" coals to unknown coals and then aggregating the results.

Total research estimates by four sulfur categories for DRB coals by state and for the nation are presented in Table B-2. (Parallel data for nine sulfur categories are presented in Table B-3.) The

Table B-2
DRB RESERVES BY FOUR SULFUR CATEGORIES
(in millions of tons)

	Sulfur Category[a]				
State	0-0.8	0.9-1.2	1.3-2.0	>2.0	Total
Alabama	3	1.287	2,084	1,625	5,000
Alaska	1,009	73	4,062	1,011	6,154
Arizona	0	0	385	25	410
Arkansas	0	11	282	117	411
Colorado.	8,313	2,358	5,386	1,225	17,281
Georgia	0	0	4	0	4
Idaho	3	1	0	0	4
Illinois	0	0	4,204	63,402	67,606
Indiana	0	215	2,283	8,088	10,586
Iowa	0	0	0	2,198	2,198
Kansas	0	0	0	994	994
Kentucky	0	10,286	5,432	18,283	34,002
Maryland	0	1	299	522	822
Michigan	0	0	0	128	128
Missouri	0	0	0	6,069	6,069
Montana	84,218	32,775	1,411	2,025	120,428
New Mexico	1,272	506	2,696	48	4,521
North Carolina	0	0	11	0	11
North Dakota	563	165	4,860	4,364	9,952
Ohio	0	0	0	19,056	19,056
Oklahoma	8	747	305	578	1,638
Oregon	12	0	6	0	17
Pennsylvania	16	561	2,608	27,095	30,281
South Dakota	0	0	267	99	366
Tennessee	0	183	291	509	984
Texas	0	0	0	12,660	12,660
Utah	398	4,716	158	1,206	6,478
Virginia	705	1,466	1,043	258	3,471
Washington	790	15	542	134	1,481
West Virginia	3,421	14,680	5,657	16,018	39,776
Wyoming	32,937	9,502	24,825	2,659	69,924
United States	133,688	79,548	69,101	190,396	472,714

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[a] Sulfur categories are in pounds of sulfur dioxide per million Btu.

Table B-3
DRB RESERVES BY NINE SULFUR CATEGORIES
(in millions of tons)

	Sulfur Category[a]								
State	0.0–0.8	.9–1.2	1.3–1.5	1.6–2.0	2.1–3.0	3.1–4.0	4.1–5.0	5.1–6.0	>6.1
Alabama	3	1,287	1,215	869	1,274	350	0	0	0
Alaska	1,009	73	0	4,062	0	1,011	0	0	0
Arizona	0	0	0	385	25	0	0	0	0
Arkansas	0	11	23	260	43	74	0	0	0
Colorado	8,313	2,358	5,159	227	1,225	0	0	0	0
Georgia	0	0	4	0	0	0	0	0	0
Idaho	3	1	0	0	0	0	0	0	0
Illinois	0	0	0	4,204	1,631	3,057	3,074	14,550	41,090
Indiana	0	215	989	1,294	517	453	2,013	1,957	3,148
Iowa	0	0	0	0	0	0	0	71	2,126
Kansas	0	0	0	0	0	190	123	210	472
Kentucky	0	10,286	3,870	1,562	429	754	1,591	7,326	8,184
Maryland	0	1	5	295	65	175	177	106	0
Michigan	0	0	0	0	95	0	26	0	7
Missouri	0	0	0	0	0	0	518	0	5,551
Montana	84,218	32,775	1,410	1	1,526	0	0	0	499
New Mexico	1,272	506	2,689	7	48	0	0	0	0
North Carolina	0	0	11	0	0	0	0	0	0
North Dakota	563	165	1,957	2,903	2,240	1,521	603	0	0
Ohio	0	0	0	0	1,117	1,307	6,553	4,385	5,694
Oklahoma	8	747	279	25	330	144	0	21	83
Oregon	12	0	0	6	0	0	0	0	0
Pennsylvania	16	561	581	2,028	8k570	12,040	3,738	1,674	1,073
South Dakota	0	0	193	74	0	99	0	0	0
Tennessee	0	183	136	155	155	60	228	30	38
Texas	0	0	0	0	12,660	0	0	0	0
Virginia	705	1,466	478	566	151	107	0	0	0
Washington	790	15	0	542	0	134	0	0	0
West Virginia	3,421	14,680	2,957	2,700	5,714	2,943	3,359	328	3,674
Wyoming	32,937	9,502	989	23,837	2,561	4	0	0	94
United States	133,668	79,548	23,101	46,001	40,552	25,450	22,003	30,657	71,732

[a] Sulfur categories are in pounds of sulfur dioxide per million Btu.

well-known patterns of U.S. coal fields are reflected in the data presented in Table B-2. Note, for example, the relatively larger quantities of lower sulfur coals in the states west of the Mississippi as well as the massive quantities of reserves in certain states such as Wyoming, Illinois, and Montana. It is these huge blocks of reserves that set these coals apart as "price-setting" coals. Note also that low-sulfur coals in the eastern states are mainly limited to a few states: Kentucky, West Virginia, and to a lesser extent, Alabama. In fact, the low-sulfur coals in Kentucky and West Virginia are geographically confined to a particular region of each state—the eastern part of Kentucky and the southern part of West Virginia.

B-3 Additional Economic Reserves

B-3.1 Estimating Quantities

The categorization of the DRB into economic and resource assurance criteria can be seen in Figure B-1, in which the coal resource data are separated into six cells. Coal resources that are "identified" include the measured, indicated, and inferred quantities. Other coal, represented by the lower third of the chart, consists of undiscovered resources, which are not quantifiable at the present time. The DRB itself occupies the upper left-hand corner of the chart. The upper right-hand corner represents the less economical resources, or those which do not meet the depth and/or thickness criteria of the DRB, but which are classified as measured or indicated coal samples. New recovery technologies such as auger mining could change the development of these resources.

The resources depicted in the middle left cell represent the types of coal that meet the current depth and thickness criteria but are in the inferred classification, and are not included in the DRB definition at present. These reserves are of interest because they can compete against coals currently being mined. Of special interest are the low-sulfur resources in this category which, as they are developed, are likely to influence coal prices and regional coal production levels. Some of the resources in this cateogry are, in fact, now being mined but cannot be quantified adequately by DOE for inclusion in the DRB because much of the data needed to fully characterize these reserves are considered proprietary by the coal companies. Again referring to Figure B-1, the middle right cell contains all other inferred resources that do not meet one of the depth or thickness criteria. Tables B-4 and B-5 show the estimates of inferred coal resources potentially available that are included in our reserve estimates but not in the DRB. These are

Figure B-1

ECONOMIC CRITERIA AND RESOURCE ASSURANCE

	Economic Viability Under Current Conditions		
Assurance of Resource	Higher	Lower	
Higher	demonstrated reserve base (500)	less economical (300)	Identified
	economical, lower assurance (300)	less economical, lower assurance (700)	
Lower	economical, undiscovered	less economical, undiscovered (2000)	Undiscovered

Note: Parentheses contain approximate reserve quantities estimated for each cell (in billion tons).

Table B-4
ADDITIONAL ECONOMIC RESERVES BY FOUR SULFUR CATEGCRIES
(in millions of tons)

State	*Sulfur Category*[a] 0-0.8	0.9-1.2	1.3-2.0	>2.0	Total
Alabama	1	953	1,435	1,774	4,163
Alaska	2,778	201	11,181	2,782	16,943
Arkansas	0	9	435	224	669
Colorado	3,622	2,281	1,399	1,992	9,294
Idaho	3	1	0	0	5
Illinois	0	0	4,895	75,382	80,277
Indiana	0	440	5,046	15,343	20,828
Iowa	0	0	0	2,761	2,761
Kansas	0	0	0	1,816	1,816
Kentucky	0	0	0	1,816	1,816
Maryland	0	0	71	150	222
Michigan	0	0	0	50	50
Missouri	0	0	0	3,974	3,974
Montana	15,167	7,092	188	655	23,102
New Mexico	375	0	13	998	1,385
Ohio	0	0	0	4,710	
Oklahoma	11	302	119	392	823
Oregon	7	0	0	0	7
Pennsylvania	257	1,085	3,726	31,283	36,352
South Dakota	0	0	227	57	283
Tennessee	0	185	293	564	1,041
Utah	112	1,958	76	753	2,899
Virginia	209	689	653	161	1,711
Washington	225	16	454	106	801
West Virginia	2,946	19,927	7,454	1,622	42,949
Wyoming	31,265	1,875	5,586	2,375	41,101
United States	56,978	40,852	45,455	165,196	308,481

[a] Sulfur categories are in pounds of sulfur per million Btu.

Table B-5
ADDITIONAL ECONOMIC RESERVES BY NINE SULFUR CATEGORIES
(in millions of tons)

State	Sulfur Category[a] 0.0–0.8	0.9–1.2	1.3–1.5	1.6–2.0	2.1–3.0	3.1–4.0	4.1–5.0	5.1–6.0	>6.1
Alabama	1	953	969	466	1,311	462	0	0	0
Alaska	2,778	201	0	11,181	0	2,782	0	0	0
Arkansas	0	9	69	366	32	193	0	0	0
Colorado	3,622	2,281	1,102	297	1,992	0	0	0	0
Idaho	3	1	0	0	0	0	0	0	0
Illinois	0	0	0	4,895	2,069	3,747	3,503	15,013	51,050
Indiana	0	440	2,270	2,776	1,168	1,215	3,220	5,276	4,465
Iowa	0	0	0	0	0	0	0	115	2,646
Kansas	0	0	0	0	0	283	178	416	939
Kentucky	0	3,838	1,444	760	280	457	468	1,322	1,745
Maryland	0	0	0	71	0	22	0	129	0
Michigan	0	0	0	0	40	0	10	0	0
Missouri	0	0	0	0	0	0	168	0	3,807
Montana	15,167	7,092	188	0	605	0	0	0	50
New Mexico	375	0	13	0	998	0	0	0	0
Ohio	0	0	0	0	253	344	1,862	531	1,720
Oklahoma	11	302	112	7	210	107	1	20	54
Oregon	7	0	0	0	0	0	0	0	0
Pennsylvania	257	1,085	802	2,924	13,738	8,507	4,505	3,638	895
South Dakota	0	0	184	42	0	57	0	0	0
Tennessee	0	185	100	192	169	75	262	19	39
Utah	112	1,958	76	0	242	511	0	0	0
Virginia	209	689	307	345	138	23	0	0	0
Washington	225	16	0	454	0	106	0	0	0
West Virginia	2,946	19,927	4,829	2,625	5,186	3,406	102	1,159	
Wyoming	31,265	1,875	232	5,354	2,365	0	0	0	0
United States	56,978	40,852	12,698	32,757	30,795	21,658	17,581	26,581	68,580

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[a] Sulfur categories are in pounds of sulfur per million Btu.

given with four and nine category sulfur values, respectively. Tables B-6 and B-7 illustrate the increase in size of the estimation of coal resources when these economic reserves are added to the DRB. In areas such as West Virginia, this increase in low-sulfur resources can be of great significance to the state's economy.

B-3.2 Implications for Modeling Results

For long-term planning and analysis, U.S. coal resource quantity estimates provide for well over 100 years of production with current or expanded production rates. Of importance to the economic growth of the coal industry is the distribution of the coal resources by quantity and quality. Supply and demand curves will be affected by this distribution.

Areas with larger quantities will not be forced into exploiting inferior high-cost seams as rapidly as areas with a lower quantity of resources available to them. Quantity will begin to affect predictions when new mines or power plants become operational, 8 to 10 years in the future. Increased quantities of eastern low-sulfur coal will affect coal prices in areas such as the critical Ohio River Basin "mixed-market" area. State and federal regulatory activities, the rate of implementation of new mining technologies, and the expected steel production level will all affect premiums for low-sulfur coal in this area.

Most analyses of projected coal prices and production levels use one of two methodologies, both of which are sensitive to the quantities of coal resources assumed to be available. The first method is the "model mine" approach used in the Department of Energy's Resource Allocation and Mine Costing (RAMC) model [3]. The RAMC model is a key component of integrating models such as the National Coal Model (NCM). The second method is an econometric method developed by Martin Zimmerman [4]. The RAMC method is used by ICF, Inc., in its Coal and Electric Utilities Model (CEUM) variant of the NCM [5,6], while the Zimmerman method is used by Data Resources, Inc. [7] in its coal service.

Both the RAMC and the Zimmerman approaches attempt to predict future prices that are sensitive to the fact that coal is a depletable resource. Thus, both methods assume that easily mineable reserves will be exploited before reserves that are harder to mine, and thus more costly.

As far as can be determined, most coal analyses use the DOE DRB as the initial supply of coal from which reserve depletion (due to production) is subtracted. To determine actual recoverable reserves, of

Table B-6
ESTIMATED COAL RESERVES BY FOUR SULFUR CATEGORIES
(in millions of tons)

	Sulfur Category[a]				
State	0-0.8	0.9-1.2	1.3-2.0	>2.0	Total
Alabama	4	2,241	3,519	3,398	9,163
Alaska	3,788	275	15,243	3,792	23,097
Arizona	0	0	385	25	410
Arkansas	0	21	717	342	1,079
Colorado	11,935	4,639	6,785	3,217	26,575
Georgia	0	0	4	0	4
Idaho	6	2	0	0	9
Illinois	0	0	9,100	138,784	147,883
Indiana	0	655	7,328	23,431	31,414
Iowa	0	0	0	4,959	4,959
Kansas	0	0	0	2,809	2,809
Kentucky	0	14,124	7,636	22,556	44,316
Maryland	0	1	371	673	1,044
Michigan	0	0	0	178	178
Missouri	0	0	0	10,044	10,044
Montana	99,385	39,867	1,599	2,680	143,530
New Mexico	1,646	506	2,709	1,045	5,906
North Carolina	0	0	11	0	11
North Dakota	563	165	4,860	4,364	9,952
Ohio	0	0	0	23,766	23,766
Oklahoma	19	1,049	423	969	2,460
Oregon	19	0	6	0	25
Pennsylvania	274	1,646	6,355	58,378	66,633
South Dakota	0	0	494	156	649
Tennessee	0	367	584	1,073	2,025
Texas	0	0	0	12,660	12,660
Utah	510	6,674	233	1,960	9,377
Virginia	913	2,154	1,696	419	5,183
Washington	1,015	31	996	240	2,282
West Virginia	6,367	34,607	13,111	28,640	82,725
Wyoming	64,202	11,377	30,411	5,034	111,025
United States	190,646	120,401	114,556	355,592	781,195

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[a] Sulfur categories are in pounds of sulfur per million Btu.

Table B-7
ESTIMATED COAL RESERVES BY NINE SULFUR CATEGORIES
(in millions of tons)

State	Sulfur Category[a] 0.0–0.8	0.9–1.2	1.3–1.5	1.6–2.0	2.1–3.0	3.1–4.0	4.1–5.0	5.1–6.0	>6.1
Alabama	4	2,241	2,185	1,335	2,586	812	0	0	0
Alaska	3,788	275	0	15,243	0	3,792	0	0	0
Arizona	0	0	0	385	25	0	0	0	0
Arkansas	0	21	91	626	75	267	0	0	0
Colorado	11,935	4,639	6,261	524	3,217	0	0	0	0
Georgia	0	0	4	0	0	0	0	0	0
Idaho	6	2	0	0	0	0	0	0	0
Illinois	0	0	0	9,100	3,700	6,804	6,577	29,563	92,140
Indiana	0	655	3,259	4,070	1,685	1,668	5,233	7,233	7,613
Iowa	0	0	0	0	0	0	0	187	4,772
Kansas	0	0	0	0	0	472	301	625	1,411
Kentucky	0	14,124	5,315	2,321	709	1,211	2,059	8,648	9,929
Maryland	0	1	5	366	65	196	177	235	0
Michigan	0	0	0	0	135	0	37	0	7
Missouri	0	0	0	0	0	0	685	0	9,358
Montana	99,385	39,867	1,598	1	2,131	0	0	0	549
New Mexico	1,646	506	2,702	7	2,131	0	0	0	549
North Carolina	0	0	11	0	0	0	0	0	0
North Dakota	563	165	1,957	2,903	2,240	1,521	603	0	0
Ohio	0	0	0	0	1,370	1,651	8,415	4,916	7,414
Oklahoma	19	1,049	391	33	540	250	1	41	137
Oregon	19	0	0	6	0	0	0	0	0
Pennsylvania	274	1,646	1,383	4,952	22,308	20,547	8,243	5,312	1,968
South Dakota	0	0	377	117	0	156	0	0	0
Tennessee	0	367	237	348	324	135	490	49	76
Texas	0	0	0	0	12,660	0	0	0	0
Utah	510	6,674	233	0	420	1,540	0	0	0
Virginia	913	2,154	785	911	289	130	0	0	0
Washington	1,015	31	0	996	0	240	0	0	0
West Virginia	6,367	34,607	7,786	5,325	10,900	5,712	6,765	430	4,834
Wyoming	64,202	11,377	1,221	29,190	4,926	5	0	0	104
United States	190,646	120,401	35,799	78,758	71,348	47,109	39,584	57,239	140,312

[a] Sulfur categories are in pounds of sulfur per million Btu.

course, some fraction of the DRB must be deducted to account for inaccessible reserves and other factors that would prevent production.

The use of the DRB as the basic starting quantity of coal supply would appear to be reasonable for forecasting analyses up to 10 years. However, the use of a static reserve estimate such as the DRB for a longer term model would appear to be inappropriate, particularly if the model seems to be showing a significant depletion effect for some coal types and/or regions. It is likely that in the areas in which existing high quality DRB type reserves become depleted, other resource categories will subsequently be exploited. Changes in market conditions may also result in exploitation of non-DRB resources.

Referring again to Figure B-1, it would appear reasonable to include, in reserve estimates, at least the additional identified resources that are economical under current conditions. This would include coal from the category of inferred coal that meets the economic (depth and thickness) criteria of the DRB. Table B-8 shows the coal resource base with accumulation of the DRB and the inferred additions, aggregated by sulfur category and region. This is the quantity referred to as "reserves" in this report.

"Compliance" coals, those that can be burned without alteration to meet a set standard, are defined for the purpose of this analysis as coals with 1.2 pounds of sulfur dioxide or less per million Btu. Such coals can be burned in power plants regulated by the 1971 New Source Performance Standard regulations that limit SO_2 emissions. Eastern compliance coal quantities would be increased by almost 80 percent with the addition of the inferred reserves. This increase in potential reserves could have a significant effect on prices in mixed market regions such as the Ohio River Basin.

A final illustration of coal reserves, estimated from different sources, is presented in Table B-9. The DOE DRB compliance/noncompliance categorization was developed based on the methodology presented earlier. The DOE LEAP figures are those used in the 1980 report to Congress [8] and the ICF figures are those reported in the Acid Rain Mitigation Study (ARMS) reports [9-13]. Finally, the E.H. Pechan & Associates (EHPA) estimates are based on applying the methodology discussed earlier to the DRB, supplemented by inferred, currently economical resources.

The significance of these results to forecasting models such as DOE's NCM or ICF's CEUM variant would be to "flatten" the supply curves that the model uses to determine sources of production. These

Table B-8
DEMONSTRATED RESERVE BASE AND INFERRED ADDITIONS BY COMPLIANCE CATEGORY
(in billions of tons)

	Eastern U.S.	Western U.S.	U.S. Total
Demonstrated Reserve Base			
Compliance	32.8	180.4	213.2
Noncompliance	178.9	80.6	259.5
Additional Economic Reserves			
Compliance	30.5	67.3	97.8
Noncompliance	172.1	38.6	210.7
Additional Economic Reserves (as percentage of DRB)			
Compliance	93	37	46
Noncompliance	96	48	81

Note: Compliance coals include all coals with a sulfur dioxide content of 1.2 pounds per million Btu or less. Noncompliance coals include all coals with a higher sulfur dioxide content.

Table B-9
SUMMARY OF DIFFERENT COAL RESERVE ESTIMATES
(in billions of tons)

Source	Compliance	Noncompliance	Percent Compliance
DOE Demonstrated Reserve Base	213.6	259.5	45.1
DOE LEAP Model Inputs	179.3	243.3	42.4
ICF	154.8	444.4	25.8
EHPA	311.0	470.1	39.8

results would also postpone the time when depletion will begin to affect resource extraction costs significantly.

B-4 The AUSM Coal Resources Data Base

This section documents the coal resources data files that were developed for the Advanced Utility Simulation Model. The model developers wished to be able to use both the coal quality categories they specified and those used by DOE's National Coal Model. In addition, separate data files were requested for DRB reserves and for total economic reserves.

Tables B-10 and B-11 identify the sulfur and heating value categories, respectively, that were

Table B-10
AUSM COAL SULFUR CATEGORIES

Code	Sulfur Dioxide Range[a]
1	0.1-0.6
2	0.7-0.8
3	0.9-1.2
4	1.3-1.5
5	1.6-2.0
6	2.1-2.5
7	2.6-3.0
8	3.1-4.0
9	4.1-6.0
10	6.1-8.0
11	>8.0

[a] In pounds per million Btu.

developed and provided by the AUSM developers. Similarly, Tables B-12 and B-13 identify corresponding values for the NCM sulfur and heating value categories.

Table B-11
AUSM HEATING VALUE CATEGORIES

Code	Rank	Heating Value (Btu per pound)
1	lignite	≤8,300
2	sub-bituminous	8,300-10,000
3	bituminous	≤10,500

Table B-12
APPROXIMATIONS OF NATIONAL COAL MODEL SULFUR CATEGORIES

Code	NCM Letter	NCM[a]	Current Study[a]
1	A	≤.40	≤.8
2	B	.4-.60	.9-1.1
3	C	.61-.63	1.2-1.3
4	D	.64-.83	1.4-1.6
5	E	.84-.92	1.7-1.8
6	F	.93-1.67	1.9-3.3
7	G	1.68-2.50	3.4-5.0
8	H	>2.50	>5.0

[a] In pounds of sulfur per million Btu.

Special attention should be given to Table B-12, which presents the NCM sulfur categories. In the detailed coal reserves and resources data base we have developed, coal is categorized in increments of 0.1 pounds per million Btu. The NCM categories, however, are based on sulfur (S) rather than SO_2 and are to the nearest .01 pound per million Btu. Thus, as shown in Table B-12, it was necessary to approximate NCM categories. Given the limitations of the available coal resource information, reserve quantities for ranges such as NCM category C cannot be computed accurately. As a result, the approximations adopted are reasonable given the inherent limitations of the data.

Note that in our data base, all coal SO_2 values have been rounded to the nearest 0.1 pound. Thus, a figure of 0.7 has the range of 0.651 through 0.749.

As a result of the AUSM specifications, four sets of data were provided. Set 1 categorizes the DRB coals according to AUSM regions, sulfur categories, and heating value categories, while Set 2 uses AUSM regions along with NCM sulfur and heating value categories. Sets 1 and 2 both use the DRB as the reserve definition. Sets 3 and 4 correspond to sets 1 and 2 in terms of regional and fuel quality category definitions, but include the larger reserve estimates discussed and documented in this report. Table B-14 summarizes these four sets of data.

Table B-13
NATIONAL COAL MODEL HEATING VALUE CLASSES

Code	NCM Letter	Grade	Heating Value Keys[a]
1	L	lignite	<15
2	S	sub-bituminous	15-19.99
3	M	bituminous	20-22.99
4	H	bituminous	23-25.99
5	Z	bituminous	>26

[a] In million Btu per ton.

summarizes these four sets of data.

The physical format for each of the four individual data files is identical and is documented in Table B-15. The data files are distributed in the form of card images (the record length is 80 characters). The tape delivered to the AUSM developers was blocked at 50 of the 80 character records per block.

Table B-16 explains the units used in the data files, and Table B-17 defines the codes for the AUSM coal supply regions.

B-5 Development of Coal Reserves Information

In earlier versions of published DRB reports, reserves information was presented by sulfur category. In more recent editions, this level of disaggregation has not been reported. This section discusses the assignment of sulfur categories to coal resource blocks.

In earlier DRB data files, sulfur content was not categorized in a substantial fraction of the reserves accounted for in the DRB (see Table B-18). The major reason is that measurements used to determine quantities of coal generally do not contain information to characterize coal quality. Thus, the assessment of quality requires the use of data from other sources.

The DOE methodology used in the DRB reports involves the aggregation of data from thousands of analytical measurements by state, county, and coal bed. On the DRB computer tape, the mean fuel quality from these measurements (as well as the range and number of measurements) is reported by state, county, and bed. We have extended this methodology to assign sulfur content to the remaining reserve base based on a hierarchical process that categorizes otherwise unassigned reserves according to the distribution of sulfur categories of assigned reserves. This process is illustrated in Figure B-2. The methodology permits two hierarchies. The first is (1) state, county, bed, (2) state, county, and (3) state. The second is (1) state, county, bed, (2) state, bed, and (3) state.

Resources which match at the highest level (state, county, bed) are assigned the sulfur category corresponding to the mean of the analytical data. Resources assigned at lower levels are distributed among the sulfur categories according to the weighted distribution of the analytic measurements within that cell. For example, all reserves with sulfur category assigned by state, county, and bed are aggregated

Table B-14
CONTENTS OF TRANSMITTAL TAPE

File	Contents
1	Demonstrated reserve base by AUSM sulfur and heating value categories
2	Additional economic reserves by NCM sulfur and heating value categories
3	Demonstrated reserve base by AUSM sulfur and heating value categories
4	Additional economic reserves by NCM sulfur and heating value categories

Table B-15
FILE CONTENTS FOR TRANSMITTAL TAPE FILES

Columns	Format	Contents
1-3	I3	AUSM region code
4-6	I3	Sulfur category
7-9	I3	Heating value category
10-17	I8	Quantity of reserves in million tons
18-25	F8.1	Average sulfur dioxide in pounds of sulfur dioxide per million Btu
26-33	F8.1	Average moisture (percentage)
34-41	F8.1	Average ash (percentage)
42-49	F8.1	Average heating value (Btu per pound)

Table B-16

UNITS USED IN THE DATA FILES

Variable	Units Reported
Sulfur category	Pounds of sulfur dioxide per million Btu
Fuel heat category	Btu per lb (AUSM categories) Million Btu per ton (NCM categories)
Average sulfur dioxide	Pounds of sulfur dioxide per million Btu
Average fuel heat	Btu per pound (wet basis)
Average moisture	Percentage by weight
Average ash	Percentage by weight

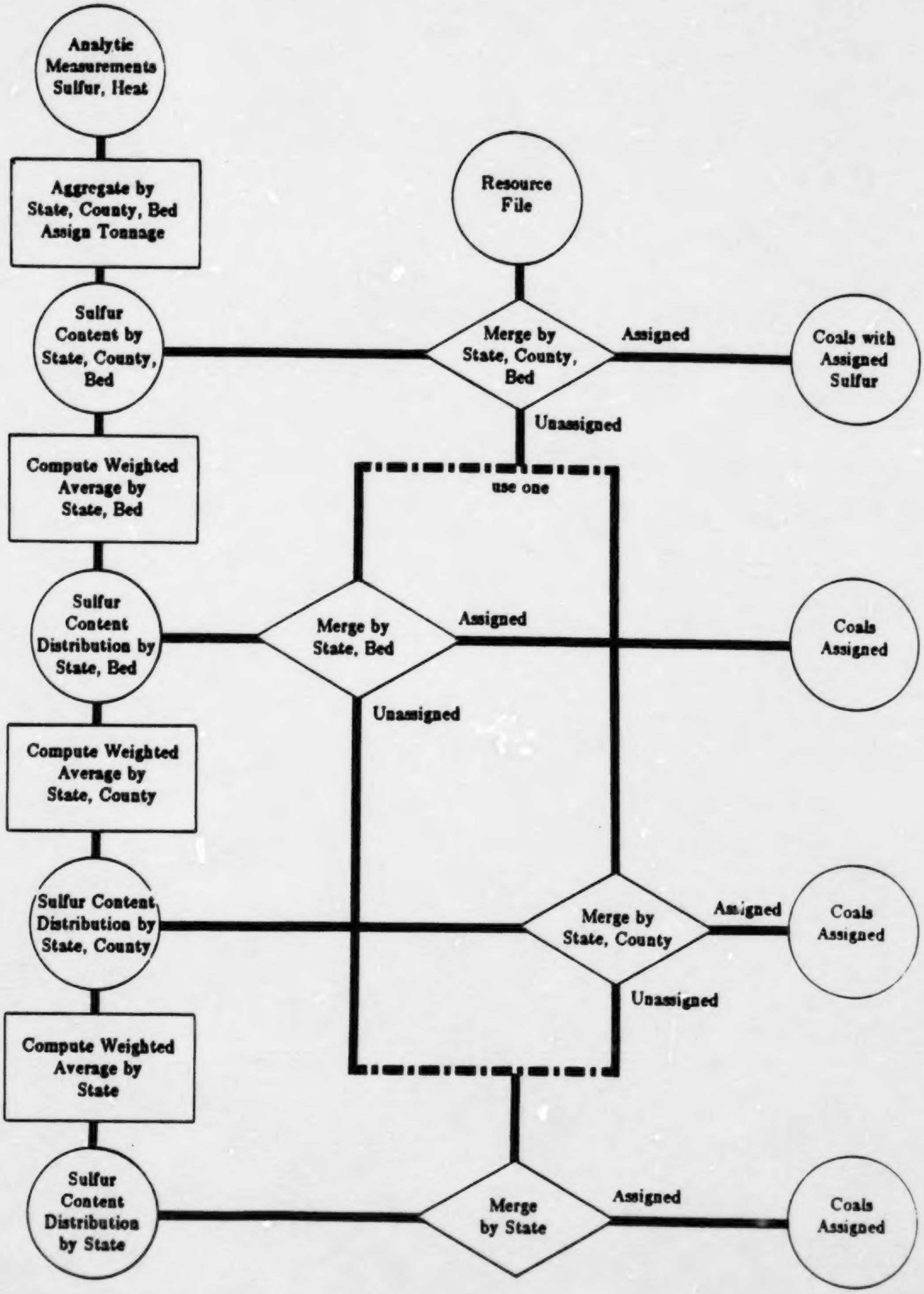
Table B-17
AUSM COAL SUPPLY REGIONS

Code	State - District	Bureau of Mines District of Origin Number
1	Pennsylvania - East	1
2	Pennsylvania - West	2
3	Maryland - West	1
4	West Virginia - East	1
5	West Virginia - North	3
6	West Virginia - Panhandle	6
7	West Virginia - Southeast	7
8	West Virginia - Southwest	8
9	Ohio	4
10	Virginia - East	7
11	Virginia - West	8
12	Kentucky - East	8
13	Kentucky - West	9
14	Tennessee - North	8
15	Tennessee - South	13
16	Illinois	10
17	Indiana	11
18	Iowa	12
19	Alabama	13
20	Arkansas	14
21	Oklahoma - East	14
22	Oklahoma - West	15
23	Kansas	15
24	Missouri	15
25	Texas	15
26	Colorado - North	16
27	Colorado - South	17
28	New Mexico - Northeast	17
29	New Mexico - West	18
30	Arizona	18
31	Wyoming	19
32	Utah	20
33	North Dakota	21
34	Montana	22
35	Washington State	23

Table B-18
COAL RESERVES BY SULFUR CATEGORY FROM THE 1974 DEMONSTRATED RESERVE BASE COMPUTER TAPE
(in billions of tons)

Pounds of SO_2 per Million Btu	Underground	Surface	Total	Percent of Total Reserves
no data	85.4	33.2	118.6	27.1
<0.8	65.7	33.0	98.7	22.6
0.9-1.2	36.4	13.5	49.9	11.4
1.3-2.0	21.0	31.4	52.3	12.0
>2.1	91.3	25.9	117.1	26.8
Total Reserves	299.8	136.9	436.8	100.0

Figure B-2
COAL SULFUR ASSIGNMENT METHODOLOGY



Analytic Measurements Sulfur, Heat
Aggregate by State, County, Bed Assign Tonnage
Resource File
Sulfur Content by State, County, Bed
Merge by State, County, Bed
Assigned
Coals with Assigned Sulfur
Unassigned
Compute Weighted Average by State, Bed
use one
Sulfur Content Distribution by State, Bed
Merge by State, Bed
Assigned
Coals Assigned
Unassigned
Compute Weighted Average by State, County
Sulfur Content Distribution by State, County
Merge by State, County
Assigned
Coals Assigned
Unassigned
Compute Weighted Average by State
Sulfur Content Distribution by State
Merge by State
Assigned
Coals Assigned

across county, and a distribution of sulfur content is created. This distribution is used to allocate reserves that match, at the highest level, on state and bed but not on county.

To produce an updated DRB including sulfur categories, however, additional analysis must be performed. The latest DRB [2] does not have a detailed file associated with it, as did previous DRB publications. It is thus necessary to go back to the original resource file, extract data according to the various DRB reserve categories, adjust for depletion, and then assign sulfur content.

Table B-19 presents the results of these manipulations. It can be seen that, according to sulfur distribution, the adopted methodology produces results that are similar but not identical to the DRB file.

The DRB represents the fraction of the ultimate coal resource that is both economical to mine under present market conditions and whose presence is highly assured. With regard to resource assurance, Figure B-1, above, showed the hierarchical arrangement of coal resources by level of assurance. Only the highest categories of identified resources, measured and indicated, are included in the DRB. The bulk of

Table B-19
DRB RESERVES BY SULFUR CATEGORY

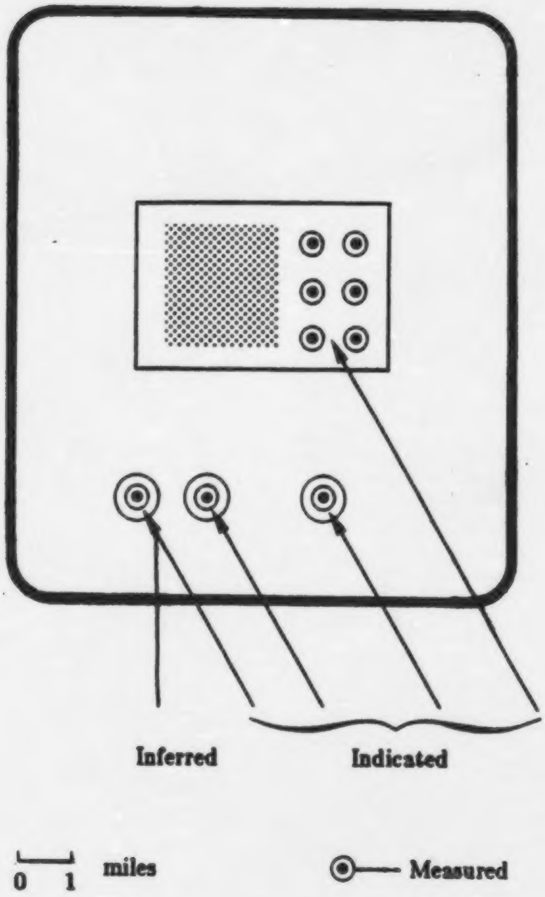
		DRB Computer Tape		*1980 DRB*	
	Pounds of SO2 per Million Btu	billion tons	percent of assigned	billion tons	percent of assigned
	0.1-0.8	98.7	31.0	133.7	28.3
	0.9-1.2	49.9	15.7	79.5	16.8
	1.3-2.0	52.3	16.4	69.1	14.6
	2.1-99.9	117.1	36.8	190.4	40.3
Total Assigned		318.0		472.7	
Unassigned		118.6		0.0	
Total Reserves		436.8		472.7	

the "ultimate" resource is in the undiscovered category. Because coal is available in vast quantities relative to many other depletable materials, there has been little incentive to delineate resources exactly. On a national basis, the DRB alone would support at least a few hundred years of production at current levels.

Figure B-3 is a schematic illustration of the categorization of identified coal resources in a coal region. The individual points are locations of samples which may represent mining operations, outcrops, drill holes, and so forth. Measured reserves are those found within one-quarter mile of the sample point, while indicated reserves are those which occur in a one-half mile band beyond the extent of the measured resources. Inferred reserves extend an additional two and one-quarter miles beyond the indicated resources.

The second dimension of the DRB is essentially the economic viability of the resource under present market conditions. As illustrated in Figure B-1, the resource assurance dimension is used to decide whether or not to include a certain coal in the DRB, and is a rather stringent criterion. To gain some insights into the amount of coal which would be available under alternative resource assurance assumptions, we defined a quantity of "supplemental" reserves that meet the DRB economic criteria but that are classified as "inferred" (rather than "measured" or "indicated," the DRB criteria), in terms of resource assurance. The result is to add almost 300 billion tons to the 500 billion tons in the DRB itself.

Figure B-3
ILLUSTRATION OF IDENTIFIED COAL RESOURCE CATEGORIES


Inferred
Indicated
0 1 miles
Measured

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APPENDIX C. COAL CLEANING METHODOLOGY

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C.1 Overview

C.1.1 Objectives

Coal "cleaning," "preparation" and "washing" are terms that describe a wide variety of processes[1] used to improve the quality of coal prior to transportation and combustion at the point of use. The general objective of these processes is to improve the value of the product coal by reducing the presence of impurities such as ash, sulfur and moisture. The reductions are obtainable only at a cost. Included are the costs both of constructing and operating the process plant and the loss of potentially combustible material which is discarded along with the refuse created by the preparation process.

The primary reason for considering coal preparation in the Advanced Utility Simulation Model (AUSM) is to assess its potential contribution in abating sulfur emissions from power plants. However, under current practice, removing sulfur from coal is a secondary consideration, the major objective being to reduce the ash content of run-of-mine coal in order to reduce transportation costs and costs incurred by the user.[2] The coal washing methodology in the AUSM accounts for both this basic level of preparation and for deeper levels of preparation that will remove significant quantities of sulfur from coal.

In general, a coal washing process can be represented by a small number of parameters. These are the process yield (the ratio of clean tons out to raw tons in), the washing cost (measured in dollars per raw ton throughout this appendix) and the properties of the cleaned coal (higher heating value plus ash, sulfur and moisture content).

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[1] These processes are described in Section C.2.1.

[2] These include waste disposal and boiler operation and maintenance costs. More speculatively, reduced ash contents may also improve plant availability.

C-1.2 Framework

A total of 33 coal categories are represented in the AUSM, comprising three coal types (lignite, subbituminous, and bituminous) broken into 11 sulfur categories (see Table C-1).[a] In the context of the AUSM coal supply module, which seeks to identify the coal with the lowest delivered cost in each of the 33 coal categories (see Chapter 4), it is convenient to regard coal washing as a technology that will shift coal from one sulfur category to another, altering its characteristics and increasing its cost. (Note that washing will not alter coal type.) For each coal type, the availability of washing processes to shift coal to lower sulfur categories may be represented by the triangular matrix shown in Figure C-1. The vertical axis represents raw coal categories, while the horizontal axis represents washed coal categories. Coals in the same column, having the same delivered sulfur content, will compete with each other. Coals that have been shifted across a number of sulfur categories will generally have a higher f.o.b. cost, but should have reduced transportation costs (measured in cents per million Btu) because their higher heating values will have been enhanced by washing. Associated with each element in the triangular matrix will be a process yield, a washing cost, a higher heating value, and an ash content. Sulfur contents are assumed to be the mid-point of the range of each sulfur category; moisture contents are not required by the pollution control module, which uses the output of the coal supply module.

Table C-1
AUSM SULFUR CATEGORIES
(in pounds of SO_2 per million Btu)

1.	≤ 0.59
2.	0.60 - 0.79
3.	0.80 - 1.19
4.	1.20 - 1.49
5.	1.50 - 1.99
6.	2.00 - 2.49
7.	2.50 - 2.99
8.	3.00 - 3.99
9.	4.00 - 5.99
10.	6.00 - 7.99
11.	≥ 8.00

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[a] An alternative categorization with five coal types and eight sulfur categories is available.

Figure C-1

TRIANGULAR FORMULATION FOR COAL WASHING

URGE Supply Region 1 PENNA (E) - Bituminous COAL

Washed Coal Types

Raw Coal Types	> 8.0	6.0-8.0	4.0-6.0	3.0-4.0	2.5-3.0	2.0-2.5	1.5-2.0	1.2-1.5	0.8-1.2	0.6-0.8	< 6.0	Number of Levels
> 8.0	X	X	X	X	X	-	-	-	-	-	-	5
6.0-8.0		X	X	X	X	X	-	-	-	-	-	5
4.0-6.0			X	X	X	X	-	-	-	-	-	4
3.0-4.0				X	X	X	X	-	-	-	-	4
2.5-3.0					X	X	X	-	-	-	-	3
2.0-2.5						X	X	X	-	-	-	3
1.5-2.0							X	X	-	-	-	2
1.2-1.5								X	-	-	-	1
0.8-1.2									X	-	-	1
0.6-0.8										X	-	1
< 0.6											-	0
Number of Coals	1	2	3	4	5	5	4	3	1	1	0	29

Notes:

X in a diagonal element means a raw coal exists.

X in an off-diagonal element means a washed coal is physically possible.

The diagonal elements of the matrix require careful interpretation. Run-of-mine coal consists of seam-quality coal diluted by quantities of extraneous material that depend on the mining method used. In order to produce a marketable product, most mines prepare coal to some degree (the sophistication of the preparation process will depend on the degree to which the seam-quality coal has been adulterated and on the properties of the coal and extraneous material). It is assumed that the coals represented by the diagonal elements in the matrices have received a basic preparation that is characteristic of a particular supply region and coal type and is sufficient to restore the coal to its seam quality. Assumptions about these basic preparation processes are documented in Section C-4. The cost of coal that has received basic preparation, C_B, is derived from the run-of-mine coal cost, C_R; obtained from the mine models; the basic preparation cost, W_B; and the basic preparation yield, Y_B, as follows:

$$C_B = \frac{C_R + W_B}{Y_B}. \tag{1}$$

The deeper washing processes represented by off-diagonal elements in the triangular matrix of Figure C-1 enhance the properties of seam-quality coal. Suppose that the cost of deeper washing is W_W and the process yield is Y_W. Then the cost of the washed coal is

$$C_w = \frac{C_R + W_W}{Y_W}. \tag{2}$$

Now suppose that the yield for deeper washing may be decomposed into two parts, Y_B, the yield associated with getting from run-of-mine coal to seam-quality coal, and Y_W^1, the yield associated with upgrading the seam-quality coal:

$$Y_W = Y_B * Y_W^1. \tag{3}$$

The derivation of W_W and Y_W^1 is the subject of the remainder of this appendix. Note that for basic preparation, $Y_W^1 = 1$ and $W_W = W_B$.

Since the diagonal elements of the triangular matrix in Figure C-1 represent seam-quality coal, these characteristics may be obtained from the U.S. Bureau of Mines (USBM) Demonstrated Reserve Base of coals in the United States [1], which is based on seam samples. The characteristic coals for each of the 33 categories and for each AUSM supply region have been established by Pechan [2].

Also, since the USBM Coal Washability Database [3] refers to the washability of seam samples, this source is used to derive estimates of Y_w^1 and the characteristics of coals washed to deeper (i.e., off-diagonal) levels.

Note that this framework also provides a convenient method for implementing mandatory washing requirements in the context of the AUSM coal supply module. Specific elements in the triangular matrix that represent low levels of washing may be artificially excluded to force significant degrees of sulfur removal. This useful addition to the ability of the coal supply module to select least-cost levels of washing is described in Section C-5, below.

C-1.3 Outline of Methodology

The methodology used has been strongly conditioned by the fact that the only consistent set of data referring to the washability of U.S. coals as a whole is contained in a data base built and maintained by the U.S. Bureau of Mines [3]. This data base currently contains information on the washability of 710 seam samples as determined under laboratory conditions (as opposed to commercial operation). Since the coal tested was of seam quality, the samples are compatible with the Demonstrated Reserve Base (DRB) [1] used to define characteristic coals (see Section C-1.2). For the same reason, the yields reported in the USBM washability data base may be interpreted as Y_w^1, identified in Equation 3.

There are two possible methods of deriving estimates of the washability of the characteristic coals defined from the DRB using the washability data base. The first is to match each characteristic coal as closely as possible with a particular sample in the washability data base with respect to geographical origin and coal properties. This approach has been used by ICF in its Coal and Electric Utilities Model (CEUM) [4]. However, the statistical properties of the USBM washability data suggest another, and perhaps more satisfactory, approach. It is observed that, within particular geographical regions, the properties of the original seam-quality coals are significantly correlated with their washabilities (this will be more precisely defined in Section C-3). Also, there is still a large unexplained residual when the explanatory properties of the coal characteristics have been accounted for. Put more simply, two apparently similar coals may have significantly different washabilities, though, for example, there is a strong trend for higher sulfur coals to be more amenable to sulfur removal through washing. The alternative approach is to derive a set of equations that predict the washability of a coal from a particular geographical region, based on its seam characteristics, using a statistical regression analysis of the USBM washability data base. This will ensure that general trends in coal washability are accounted for while avoiding the possibility inherent in the ICF approach that characteristic coals may be matched to unrepresentative washability samples. The regression analysis is described in Section C-3.

There are two reason why the USBM washability data base cannot be used directly in such an analysis. First, the data base contains no information on washing costs; second, the washability tests were carried out under laboratory conditions that are not reproducible in commercial operations. A preparation plant model has been developed that adjusts the physical washability data to allow for the "inefficiency" of preparation processes and establishes preparation costs in dollars per ton of raw coal based on the estimated cost of constructing and operating a preparation plant. This model, and the way it was used, are described in Section C-2.

Section C-4 describes how the washing equations described in Section C-3 were used to establish washed coal properties, washing yields, and washing costs that can be used in the coal supply module framework discussed in Section C-1.2.

Section C-5 is a description of how possible mandatory washing requirements are implemented in the coal supply module.

C-2. A Model of Coal Preparation Plant Operation

C-2.1 Coal Preparation

Physical coal cleaning is carried out using a variety of individual processes including crushing, screening, specific gravity separation, and froth flotation, which have a long history of commercial operation. Coal preparation has become more common as the degree of mechanization in U.S. coal mines has increased, since mechanization leads to higher proportions of fine sizes and impurities in mined coal. The primary objectives of coal preparation are to achieve a greater degree of uniformity of particle size and to reduce ash content in order to lower transportation and waste disposal costs incurred by the final user. Physical coal cleaning also reduces the sulfur content of coal by removing pyritic sulfur, which takes the form of discrete particles. Organic sulfur, which forms an integral part of the coal matrix and may comprise 30 to 70 percent of total sulfur content, can be removed only by chemical processing.

Many different types of process plant are used for physically washing coal. These include jigs, concentrating tables, dense medium vessels, cyclones, and froth flotation devices. The principles of operation of these devices are comprehensively described in the literature [5,6,7,8]. Essentially, apart from froth flotation, all these devices separate higher quality product coal from low-grade refuse using the principle that impurities in coal generally have a higher specific gravity than the combustible material. Jigs operate by pulsing water through a bed of coal so that the lighter particles gravitate toward the top. A concentrating table consists of an inclined riffled surface, which is vibrated as a mixture of coal and water flows over it. Dense media vessels contain suspensions of sand or magnetite in water; these have effective specific gravities greater than one. Product coal floats to the surface while refuse sinks to the bottom. Cyclones, which use centrifugal as opposed to gravitational forces, are employed in conjunction with either coal-water mixtures (hydrocyclones) or coal in a dense medium (dense media cyclones). Froth flotation devices are used for fine coal under the principle that certain solids (in particular the combustible part of coal) adhere selectively to air while others (mineral material) adhere to water. Different washing processes are appropriate depending on the particle size of the coal to be washed and the extent to which the qualities of the product are to be enhanced.

Specific gravity processes do not produce a sharp separation between particles heavier than the characteristic specific gravity of separation and those which are lighter. The performance of washing plant may be described by partition or distribution curves of the type shown in Figure C-2. This diagram shows that some light particles join the refuse, while some heavy particles join the float. Several different measures relate to the amount of misplaced material associated with the washing process. The error area, which is shaded in Figure C-2, is one such measure. Another is the probable error, defined as half the specific gravity interval spanned by the partition curve in passing from the 25 percent to the 75 percent recovery ordinates. Typical probable errors for different types of washing equipment are shown in Table C-2.

Figure C-2

PARTITION CURVE FOR COAL WASHING IN A BAUM JIG

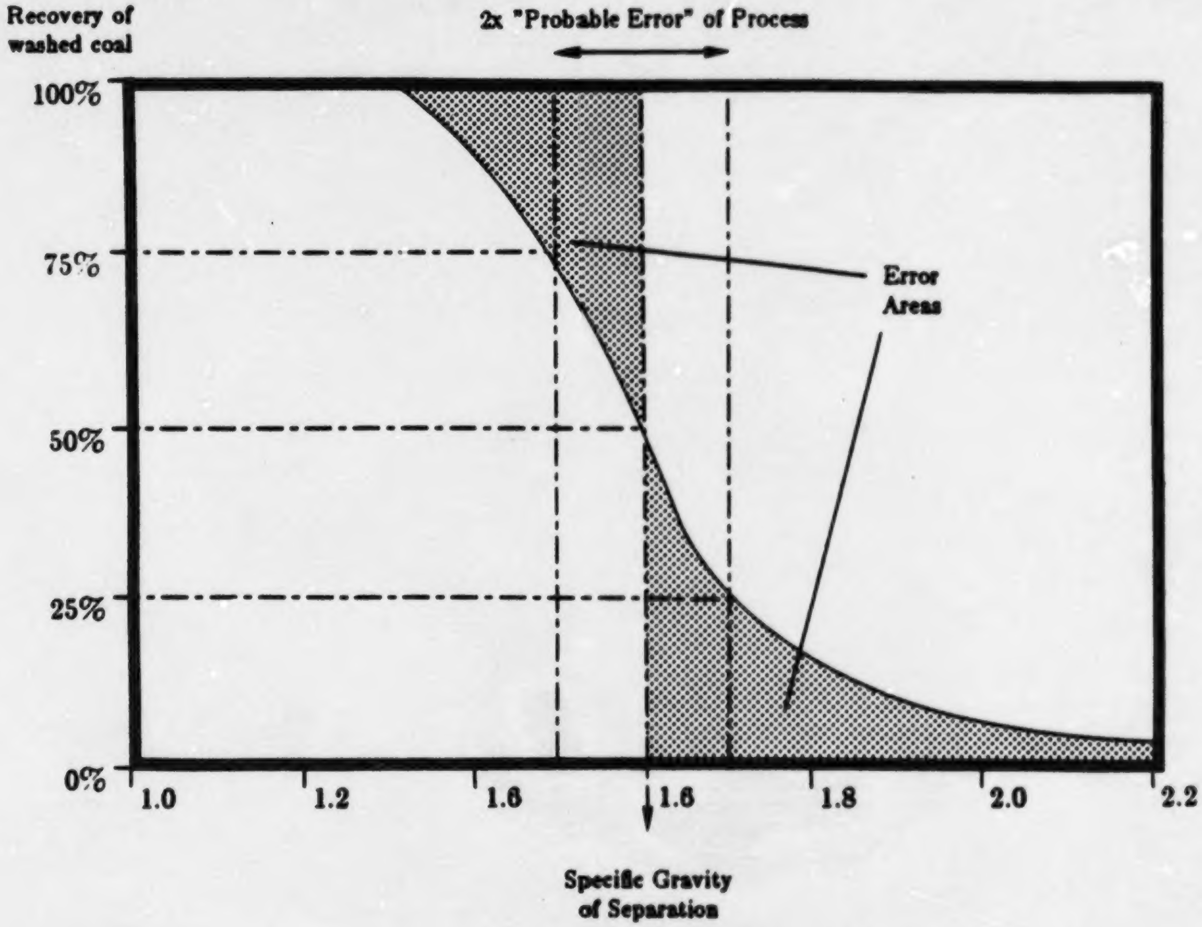

Table C-2

TYPICAL PROBABLE ERRORS FOR COAL WASHING EQUIPMENT

(in specific gravity units)

Type of Equipment	Probable Error (Sg)
Jigs	± 0.10
Concentrating tables	± 0.09
Hydrocyclones	± 0.09
Heavy medium cyclones	± 0.03
Heavy medium vessels	± 0.035

Source: Reference 5.

Coal preparation plants operate by screening coal into several streams differentiated with respect to particle size. Each of these streams may be treated in a different manner. For the purposes of this model, four generic levels of preparation plant are identified [6,7]. A summary of the activities associated with each of these levels, including the types of washing equipment used, is shown in Table C-3. The choice of equipment for processing the different coal streams can vary considerably, but the items shown in Table C-3 should be reasonably representative.

The size ranges of the coal processed varies from plant to plant, but as an approximation "topsizes" refers to coal particles greater than one-quarter to one-half inch, "midsizes" to coal particles down to 14 to 28 mesh, and "finesizes" to smaller particles. Generally, a preparation plant will be designed to produce coal of a certain target quality at a minimum cost. Cost will be minimized when one maximizes the overall yield of the plant--defined as the ratio of coal into the plant to coal coming out. By balancing the specific gravities of separation, and hence the yields for the different preparation streams, it is possible to optimize the overall plant yield while meeting the required quality target.

The operational details of a preparation plant depend on the washability characteristics of the coal

Table C-3
TYPICAL PROCESSES IN FOUR LEVELS OF PREPARATION PLANT[a]

Level of Preparation	Topsizes	Midsizes	Finesizes
1	no cleaning	no cleaning	no cleaning
2	heavy medium cyclone	no cleaning	no cleaning
3	heavy medium vessel	heavy medium cyclone drying	no cleaning
4	heavy medium vessel	heavy medium cyclone drying	hydrocyclone drying

[a] In addition to crushing and screening.
Source: References 6 and 7.

to be cleaned. An example of washability data is shown in Table C-4.[4] Data are recorded for three different size fractions; they have not been adjusted for the efficiency of washing equipment. As the specific gravity of separation increases, the recovery of coal increases, accompanied by a lowering of coal quality. Thus, there is a tradeoff to be made between coal quality and recovery.

C-2.2 Model Overview

This model [9] is a development of one previously constructed at Carnegie-Mellon University [10]. It has been designed specifically for processing the USBM data base.

A summary flowsheet of the model is shown in Figure C-3. Washability data may come in a variety of forms. The first stage is to manipulate the raw data provided into a form which represents the washability of the coal streams in the particular plant being modeled. The second step is to adjust the washa-

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[4] Coal characteristics are expressed here on a dry basis, i.e., as if all moisture in the coal had been evaporated. This provides a stable and consistent basis for characterizing a coal whose moisture content may vary considerably during the preparation process. All coal qualities, such as ash, sulfur, and Btu contents, are expressed on this basis throughout this appendix. However, it should be noted that coal qualities are usually reported on a moist, as-delivered basis.

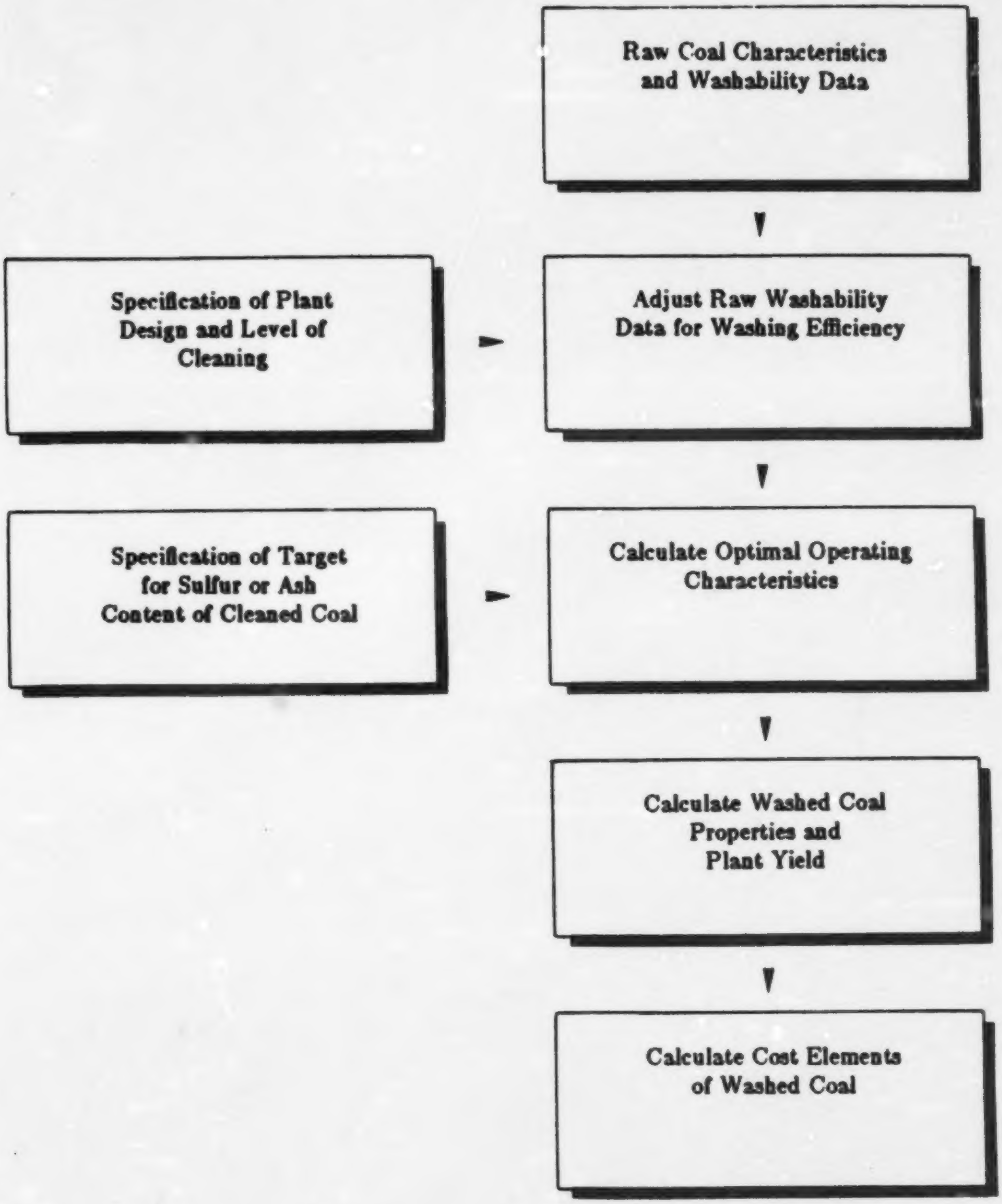
Table C-4

SAMPLE WASHABILITY DATA: UPPER FREEPORT SEAM, BUTLER COUNTY, PENNSYLVANIA

Fraction	Percent Weight Recovery	Btu per Pound	Percent Ash	Percent Pyritic Sulfur	Percent Total Sulfur
2" x 3/8"					
Float-1.30	38.2	14,589	3.4	0.44	0.85
Float-1.40	62.4	14,810	6.0	0.85	1.40
Float-1.50	70.9	13,947	8.3	1.03	1.55
Float-1.60	74.9	13,766	9.5	1.13	1.67
Float-1.80	79.4	13,486	11.5	1.37	1.89
Total	100.0	11,581	24.3	2.89	3.36
3/8" x 28 mesh					
Float-1.30	45.8	14,604	3.3	0.43	0.85
Float-1.40	64.0	14,356	5.4	0.59	1.07
Float-1.50	70.5	14,005	6.3	0.67	1.13
Float-1.60	74.0	13,851	7.4	0.75	1.21
Float-1.80	77.1	13,649	8.9	0.86	1.32
Total	100.0	11,414	23.5	2.68	3.40
28 mesh x 0					
Float-1.30	46.3	14,649	3.0	0.32	0.74
Float-1.40	65.0	14,411	4.6	0.50	0.96
Float-1.50	72.0	14,184	5.7	0.61	1.08
Float-1.60	75.9	14,012	6.5	0.74	1.21
Float-1.80	79.4	13,746	7.8	0.87	1.34
Total	100.0	11,680	21.4	3.00	3.51

Source: Reference 7.

Figure C-3
SUMMARY FLOWSHEET OF MODEL


Raw Coal Characteristics and Washability Data
Specification of Plant Design and Level of Cleaning
Adjust Raw Washability Data for Washing Efficiency
Specification of Target for Sulfur or Ash Content of Cleaned Coal
Calculate Optimal Operating Characteristics
Calculate Washed Coal Properties and Plant Yield
Calculate Cost Elements of Washed Coal

bility data to take account of the efficiency of washing equipment as represented by the probable error in the specific gravity of separation. Given a target for the sulfur content of the final coal, the Lagrange multiplier technique is used to calculate the operational details which will result in the maximum overall recovery of coal. The model identifies the value of the Lagrange multiplier which will yield the optimal operating characteristics and uses it to derive the properties of the washed coal and the process yield for each coal stream. Finally, the cost of the washed coal is estimated, based on the cost of raw coal, the running costs of the plant, and the amortized capital cost of the plant. Each stage shown in Figure C-3 will now be described in more detail.

C-2.3 **Manipulating Washability Data**

Washability data are sometimes supplied in a form which is cumulative with respect to particle size. For example, the USBM gives data for size ranges 1.5 inch x 0, 0.375 inch x 0, and 14 mesh x 0. However, the screened size ranges of the coal actually washed in plant would be 1.5 inch x 0.375 inch, 0.375 inch x 14 mesh, and 14 mesh x 0. To alter the washability data appropriately, it is necessary to know the size distribution of particles in the raw coal.

Suppose that a size fraction X x 0 accounts for a fraction f_x of the raw coal, and a fraction Y x 0 for f_y. Then, if for a particular specific gravity of separation the corresponding yields are Y_x and Y_y, the yield for the size fraction X x Y will be given by

$$y = \frac{Y_x f_x - Y_y f_y}{f_x - f_y} . \tag{4}$$

In addition, suppose that the product coal from the X x 0 fraction has a particular quality q_x (which could be sulfur, ash, or Btu content) and that the corresponding value for the Y x 0 fraction is q_y. The product coal from the X x Y fraction would then have the quality

$$Q = \frac{Y_x f_x q_x - Y_y f_y q_y}{Y_x f_x - Y_y f_y} . \tag{5}$$

The washability data are adjusted for washer efficiency as follows. The partition curve for a particular process using a particular specific gravity of separation, such as that shown in Figure C-2, may be described by the functional form $r = r(g)$, where r is the fraction of coal of specific gravity g joining the described by the functional form $r = r(g)$, where r is the fraction of coal of specific gravity g joining the float, i.e., the cleaned coal product stream. If $f(g)dg$ is the fraction of the raw coal with specific gravity lying between g and $g + dg$, then the adjusted yield for the process is

$$y = \int_0^\infty r(g)f(g)dg \ . \tag{6}$$

If the quality of coal (sulfur, ash, or Btu content) with specific gravity g is $q(g)$, then the quality of the cleaned coal is

$$q = \frac{\int_0^\infty r(g)f(g)q(g)dg}{\int_0^\infty r(g)f(g)dg} , \tag{7}$$

where $f(g)$ and $q(g)$ may be deduced from washability data of the type shown in Table C-4. In a particular specific gravity range, $f(g)$ is assumed to be constant. For example, for the top-size shown in Table C-4, $f(g)$ in the range 1.3 to 1.4 is (0.626-0.382)/(1.4-1.3) = 2.42. In the present model, $q(g)$ is assumed to be a piecewise linear function, and $r(g)$ is assumed to be dependent only on the type of washing equipment and to take the piecewise linear form shown in Figure C-4. Piecewise linear functions are an adequate and computationally simple way to represent washability curves. Therefore, $r(g)$ is completely defined by a specific gravity of separation and a "probable error" for the washing process. Typical probable errors for different items of washing equipment are shown in Table C-2.

Figure C-5 shows a plot of the reduction in sulfur content of a washed coal as a function of mass yield at various values of the probable error. These are derived by applying Equations 6 and 7 to a typical washability curve for a Pennsylvania coal. The results are in good agreement with the actual performance of coal cleaning plants. With reference to the probable errors indicated in Table C-2, it is apparent that for certain items of equipment, notably jigs, concentrating tables, and hydrocyclones, the effects of washing inefficiency can be significant at low process yields.

One final adjustment is made since the coal quality targets for the model are expressed in terms of pounds of SO_2 per million Btu, and Btu recovery is to be maximized. The weight recovery data are con-

Figure C-4

IDEALIZED WASHING PARTITION CURVE

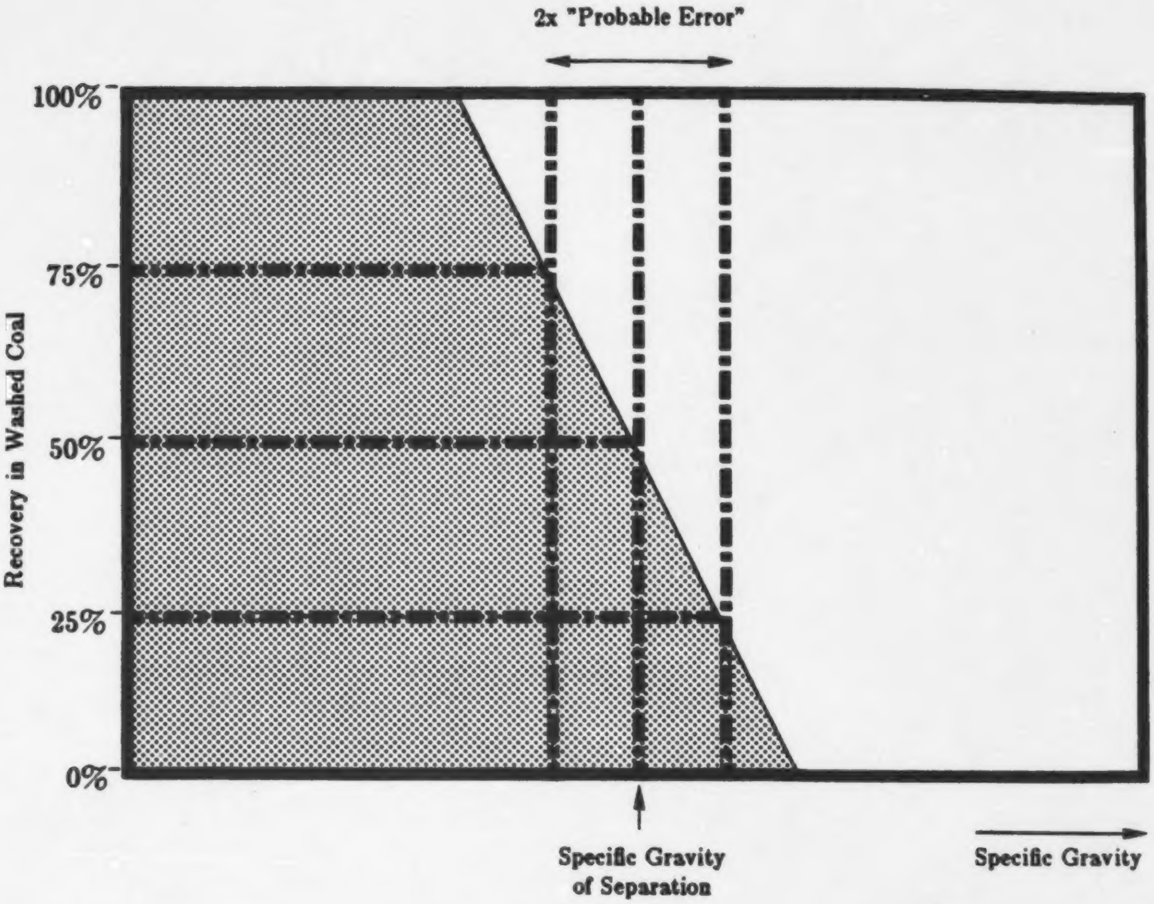
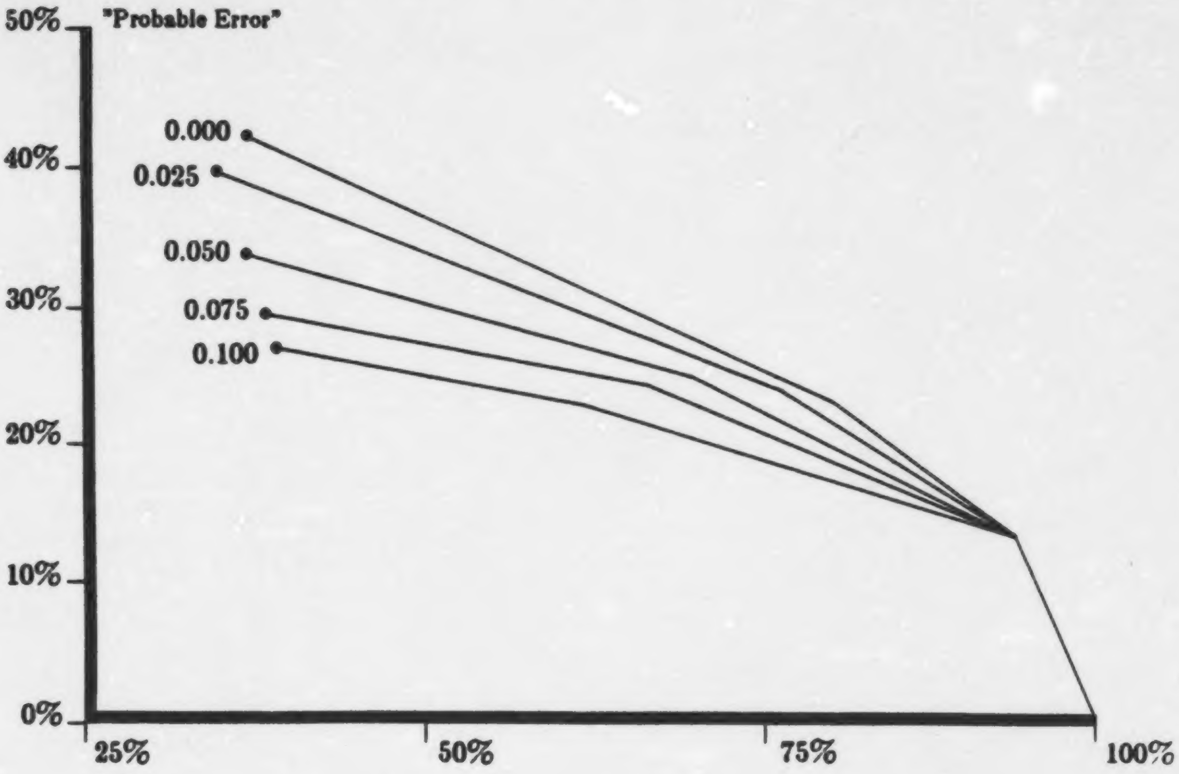


Figure C-5
EFFECT OF PROBABLE ERROR IN SULFUR REDUCTION



pounds of sulfur per million Btu.

C-2.4 Optimizing Plant Operation

The technique described here for maximizing plant yield rests on the assumption that, for any particular washing process, washed coal quality (i.e., sulfur, ash, or Btu content) can be described as a function of the process yield (expressed in terms of Btu recovery). Thus, if the coal quality is q, $q = q(y)$. Suppose that there are N wash streams denoted by the index i. Suppose also that the fraction of the raw coal (measured by Btu content) associated with stream i is f_i, such that $\sum_{i=1}^{N} f_i = 1$. Then, the overall plant yield is

$$Y = \sum_{i=1}^{N} f_i y_i \, . \tag{8}$$

The quality of the washed coal is given by

$$Q = \frac{\sum_{i=1}^{N} f_i y_i q_i(y)}{\sum_{i=1}^{N} f_i y_i} = Q* \tag{9}$$

where $Q*$ is the target quality. Thus, we wish to maximize $Y(y_1, ..., y_n)$ subject to the constraint:

$$\sum_{i=1}^{N} f_i y_i [q_i(y_i) - Q*] = 0. \tag{10}$$

Using the Lagrange multiplier technique for optimization subject to constraints, the following equation must be satisfied for each wash stream:

$$f_i - \lambda [f_i q_i - f_i Q* + f_i y_i \frac{dq_i}{dy_i}] = 0 \tag{11}$$

where λ is the undetermined Lagrange multiplier. Therefore, it follows that the quantity:

$$q_i + y_i \frac{dq_i}{dy_i} = q_i'(y_i) = \frac{1}{\lambda} + Q* \tag{12}$$

must be equal for each wash stream. It is possible to write each y_i and q_i as a function of q_i' and hence solve Equation 10 for the optimal value of q_i'. The optimal yield can then be calculated and may in turn be used to calculate the final coal properties from the washability data.

In practice, within the computer model, the coal qualities are set up as piecewise linear functions of the process yield from washability data of the type shown in Table C-4, making calculation of the optimal mode of operation relatively simple. One subroutine sets up the functions $q_i'(y_i)$, while another searches the linear segments of these functions for an optimal solution, starting at the ends of the functions representing the highest recoveries of coal. A solution which would involve a process yield less than that covered by the available washability data (see, for example, Table C-4) is not considered feasible. It is assumed that any coal quality target which would involve such low yields cannot be met.

C-2.5 Thermal Drying of Washed Coal

Normally, it is necessary to thermally dry (as opposed to physical drying in centrifuges, for example) the fine sizes of washed coal, which can accumulate large quantities of moisture during the washing process. Sometimes it may also be necessary to thermally dry the midsizes. In the model, it is assumed that both these size ranges are thermally dried at level 3 and 4 plants. Product coal is normally used to fire the driers, thus reducing the overall yield of the plant. Drying significantly alters only the moisture content of coal, and all other qualities, such as ash, sulfur, and Btu content (measured on a dry basis), remain essentially the same. (Some sulfur is in fact adsorbed from the hot combustion gases, but the effect is negligible.)

Suppose the moisture content of the coal entering the drier is M_{in} and that of the coal leaving the drier is M_{out}. If one pound of dry coal is processed, then m' pounds of moisture have been evaporated where:

$$M' = \frac{M_{in} - M_{out}}{(1 - M_{in})(1 - M_{out})}. \tag{13}$$

This will require E = 1020 * M' Btu of energy. If the higher heating value of the cleaned coal (on a dry basis) is HHV(Btu/lb), then the lower heating value may be approximated by:

$$LHV = 0.96 * HHV - \frac{1020 * M_{out}}{1- M_{out}} . \qquad (14)$$

The factor of 0.96 allows for the energy required to evaporate the water formed from the hydrogen content of the coal, while the second term allows for the energy required to evaporate the moisture content. Therefore, the fraction of the cleaned coal required to fire the thermal driers is given by:

$$\frac{f * E}{e * LHV} \qquad (15)$$

where f is the fraction of the cleaned coal which must be dried and e is the thermal efficiency of the drier. Therefore, plant drying yield $Y_D = 1 - (f * E) / (e * LHV)$, and the overall cleaning plant yield is $Y_T = Y_C * Y_D$, where Y_C is the cleaning yield. The values assumed for e, M_{in} and M_{out} are shown in Table C-5.

C.2.6 Cleaning Costs

Two elements of the cost of cleaning coal are identified in the model: (1) plant operating costs and (2) capital-related costs.

Item (1) comprises a wide range of cost elements, including labor, maintenance, raw materials and waste disposal costs. Based on a detailed analysis of the costs of preparation plants of various designs, typical cost factors for each of the four generic plant levels derived. These are shown in Table C-6. It should be noted that the cost factors relate to a number of different attributes of preparation plant operation. Reference 6 shows that labor costs are insensitive to plant throughput over a range of 400 to 1,000 tons per hour. They were related only to hours of plant operation. Maintenance costs were taken to be proportional to the total capital cost of the plant. The costs of services and chemicals were linked to the mass rate of coal entering the plant, while the cost of waste disposal was assumed to be proportional to the quantity of coal rejected. "Overheads" based on labor, maintenance and materials are a significant additional component of total operating costs.

Item (2), capital-related costs, consists of the amortized capital cost of the plant, interest on working capital and an allowance for administration, taxes and insurance. To estimate capital costs, the preparation plant is divided into five sections, or components: (1) coal storage and handling, (2)

Table C-5
INPUT ASSUMPTIONS FOR THE COAL PREPARATION PLANT MODEL

Sizes of coal streams	Topsize: 1-1/2" x 3/8" Midsize: 3/8" x 14 mesh Finesize: 14 mesh x 0
Coal streams thermally dried	Levels 1 and 2: none Level 3: midsizes Level 4: fine and midsizes
Annual plant operation	3,325 hours
Plant output capacity	500 tons per hour
Economic life of plant	20 years
Moisture in coal entering thermal drier	20 percent
Moisture in coal leaving thermal drier	5 percent
Efficiency of thermal drier	50 percent
Probable errors for washing equipment	See Table C-2
Index updating costs to mid-1980 dollars (mid 1978 = 100)	121.0

Table C-6
PREPARATION PLANT OPERATING COST FACTORS

Variable Cost Element	Level of Preparation[a] 1	2	3	4
Labor[b,c] (dollars per hour)	103.80	135.24	139.35	224.90
Maintenance[c] (percent of total capital cost)	7.0	7.0	7.0	7.0
Services[d] (cents per ton raw coal)	2.0	6.6	13.6	15.4
Chemicals[c,e] (cents per ton raw coal)	-	2.5	4.3	7.1
Waste Disposal (dollars per ton rejected coal)	-	1.00	1.00	1.00

[a] See Table C-3.

[b] Cost per hour of plant operation, based on two shifts, 250 days per year. An additional 30 percent of the labor costs is allowed as a payroll overhead.

[c] An additional 26 percent of these costs is allowed as a plant overhead.

[d] Water and electricity costs per ton of raw coal feed.

[e] Costs for magnetite, flocculant, methyl isobutyl carbinol (MIBC), and fuel oil per ton of raw coal.

coal cleaning, (3) thermal drying, (4) clean coal handling, and (5) refuse handling. There are assumed to be economies of scale in each section [6], with the direct capital costs, $K_{d,i}$, of component i taking the form:

$$K_{d,i} = a_i \, (T_i)^{0.7} \tag{16}$$

where a_i is a constant and T_i is a characteristic mass throughput rate for component i. Only the cost of the coal cleaning section is assumed to vary from one level of coal preparation plant to another. Values for the constant a_i and a description of the appropriate throughput parameters are shown in Table C-7. In addition to the direct costs shown in the table, a markup of 135 percent on the cost of the cleaning plant section is allowed for installation, buildings and service costs. Markups of 10 percent on each section are allowed for each of three items, namely, engineering costs, construction and field costs, and contractor's fee. Finally, there is a 25 percent contingency allowance in addition to the total direct and indirect costs. Thus, the total capital cost, K_T, is calculated as

$$K_T = 1.25 \left(1.35 * 1.3 K_{d,2} + 1.3 \sum_{i=1}^{5} K_{d,i} \right) \qquad (17)$$

Working capital requirements are assumed to be 25 percent of preparation plant operating costs (see Table C-6) exclusive of payroll (labor costs) and plant overheads. Administrative costs, taxes and insurance are assessed as 4 percent of the total capital cost given by Equation 17.

Table C-7
CAPITAL COST PARAMETERS FOR EQUATION 17 [7]

Plant Section		a_i (dollars)	T_i (tons per hour)
1. Storage and handling		12,800	raw coal input
2. Cleaning:	Level 1	2,600	raw coal input
	Level 2	8,800	raw coal input
	Level 3	15,300	raw coal input
	Level 4	19,600	raw coal input
3. Thermal drying		116,600	rate of moisture evaporation
4. Clean coal handling		7,100	washed coal output
5. Refuse handling		24,300	refuse coal disposal

Note: This table provides direct capital costs. Indirect costs are assumed to be 205 percent of Section 2 plus 30 percent of Sections 1, 3, 4 and 5. Contingencies are assumed to be an additional 25 percent of direct plus indirect costs.

C.2.7 Using the Preparation Plant Model to Process the USBM Data Base

A sample of the type of data contained in the U.S. Bureau of Mines (USBM) washability data base is given in Table C-8. This sample is exactly as supplied by the Bureau of Mines, except for the addition of higher heating values, which were not present in the original data base. Higher heating values are calculated according to the following formula:

$$H = a - b\,(A + 0.3\,P + 0.5\,O) \qquad (18)$$

where H is the higher heating value of the coal; A, P and O are the ash, pyritic sulfur and organic sulfur percentages of the coal. a and b are coal-specific constants determined from regression analysis by the Bureau of Mines [11]. Note that all the coal properties are expressed in dry terms, which is consistent with the required format for the preparation plant model previously described. The data base also contains information on the fractions of coal crushed to 1-1/2 inch top size with sizes greater than 3/8 inch and 14 mesh.

The cleaning model was exercised three times for each coal in the data base, once for each of the three generic levels of preparation plant (Levels 2, 3 and 4) which may result in a reduction of coal sulfur content. A series of results was obtained for each level, giving reductions in sulfur content (measured as pounds of SO_2 per million Btu) in increments of 5 percent up to the maximum level of reductions implied by the washability data. Table C-5 shows the basic assumptions which were made in exercising the cleaning model.

As shown in Table C-9, the following items of information are output from the model for each level of sulfur reduction: (1) percent sulfur reduction, (2) ash content, (3) Btu content, (4) process (weight) yield and (5) five cost elements for washed coal.

In addition to these data items, a set of location codes is given for each coal, as well as the percentage of the sulfur content which is pyritic. The cost of coal cleaning was broken into five elements to allow the maximum flexibility in escalating different cost components at different rates in the AUSM coal

Table C-8
USBM WASHABILITY DATA

STATE: Ohio
COUNTY: Belemont

COAL BED: Waynesburg
RAW COAL MOISTURE: 2.9%

Product	Recovery Weight	Percent Btu	Btu per Pound	Percent Ash	Sulfur Pyritic	Sulfur Total	Pounds of SO2 per Million Btu
Sample Crushed to Pass One and One-Half Inches							
Float - 1.30	7.2	8.3	13,873	4.7	.44	1.39	2.0
Float - 1.40	68.6	73.5	12,686	10.9	1.05	1.96	3.1
Float - 1.60	91.0	94.2	12,380	14.0	1.15	1.97	3.2
Total	100.0	100.0	11,893	16.9	1.82	2.61	4.4
EPA standard	-	-	-	-	-	-	1.20
Sample Crushed to Pass Three-Eighths Inch							
Float - 1.30	10.0	11.6	14,003	3.9	.27	1.28	1.8
Float - 1.40	65.9	72.1	13,087	9.6	.68	1.63	2.5
Float - 1.60	87.6	92.4	12,561	12.9	.89	1.78	2.8
Total	100.0	100.0	11,803	17.4	2.06	2.85	4.8
EPA standard	-	-	-	-	-	-	1.20
Sample Crushed to Pass 14 Mesh							
Float - 1.30	23.4	27.1	14,051	3.6	.27	1.27	1.8
Float - 1.40	64.2	71.4	13,417	7.6	.47	1.38	2.1
Float - 1.60	84.7	90.5	12,864	11.2	.59	1.47	2.3
Total	100.0	100.0	11,889	16.9	1.96	2.72	4.6
EPA standard	-	-	-	-	-	-	1.20

Table C-9
PREPARATION PLANT MODEL OUTPUT

STATE: Ohio
4.39 pounds of SO_2 per million Btu
16.9% ash
11,893 Btu per pound
69.7% pyritic sulfur

					Costs				
Percent Reduction SO_2	Pounds of SO_2 per Million Btu	Percent Ash	Btu per pound	Weight Yields (Percent)	C_1[a]	C_2[b]	C_3[a]	C_4[a]	C_5[a]
0.0	4.39	16.9	11,893	100.0	1.19	6.9	0.19	0.89	0.16
5.0	4.17	16.6	11,976	99.1	1.23	7.1	0.20	0.89	0.16
10.0	3.95	15.9	12,059	98.1	1.28	7.2	0.21	0.89	0.16
15.0	3.73	15.3	12,160	96.7	1.36	7.6	0.22	0.89	0.16
20.0	3.51	16.7	12,264	95.3	1.61	7.6	0.26	0.89	0.16
25.0	3.29	14.0	12,370	93.9	1.48	7.8	0.25	0.89	0.16
30.0	3.07	12.2	12,658	80.1	2.02	9.1	0.36	0.89	0.16
35.0	2.85	10.2	12,984	59.0	3.28	11.9	0.63	0.89	0.16
40.0	2.63	9.3	13,160	41.3	5.19	15.9	1.05	0.89	0.16
45.0	2.41	7.9	13,366	21.9	10.53	24.9	2.24	0.89	0.16

[a] In dollars per ton.

[b] In dollars per annual ton.

Note: See Section C-2.7 for an identification of costs.

supply module. These are (1) nonlabor operating costs (dollars per ton), (2) capital costs (dollars per annual ton), (3) working capital not proportional to labor (dollars per annual ton), (4) labor costs (dollars per ton), and (5) working capital proportional to labor (dollars per annual ton).

C-3. General Equations for Predicting Coal Washability

This section describes the selection of appropriate geographical regions in which to segregate the information in the washed coal data base, the selection of appropriate functional forms to describe coal washability curves, and the methodology used to determine the values of the coefficients in the equations. The first step in the process was to determine which variables are likely to be relevant in a particular equation. Since washability curves are highly nonlinear, the second step was to identify the appropriate mathematical transformations which would allow standard multiple linear regression techniques to be used to determine the values of coefficients.

C-3.1 Selection of Washability Regions

Each coal in the U.S. Bureau of Mines data base is assigned to one of 18 different geographical regions of the United States. Ideally, there would have been 35 regions corresponding to the AUSM supply regions, but the number of samples in many of these regions was insufficient to provide an adequate basis for a statistical analysis. The AUSM supply regions were aggregated for the analysis according to the following set of priorities:

1. Regions in the same USBM producing district
2. Regions in the same state
3. Regions in the same USBM producing region
4. Regions in broad geographical proximity.

The composition of the 18 regions is shown in Table C-10, along with the number of Bureau of Mines washability samples associated with each.

C-3.2 Equations for Physical Results of Washing

These equations are required to determine whether a requested degree of sulfur removal is possible and, if so, to estimate the resulting ash and Btu contents of the washed coal, plus the Btu yield of the process. The main independent variable in the equations is the reduction in sulfur content, measured in pounds of SO_2 per million Btu equivalent. Because other coal properties (such as the percent ash) are to be reported with respect to the weight of coal, some algebraic manipulation is required. To avoid confusion, a complete list of symbols used in the description is shown in Table C-11.

Note that for ease of exposition, coal properties are expressed in fractional terms, although the computer program which makes the calculations accepts input and generates output in percentage terms. A set of identities links coal properties expressed in Btu terms to those expressed in weight terms. These

Table C-10
DEFINITION OF WASHABILITY REGIONS

Washability Region	AUSM Region	AUSM Region Name	Number of USBM Samples
1	1	East Pennsylvania	143
2	2	West Pennsylvania	62
3	3,4	N.E. West Virginia/Maryland	39
4	5,6	N.W. West Virginia/West Virginia Panhandle	32
5	7,8,10,11	SE/SW West Virginia/Virginia	24
6	9	Ohio	148
7	12,14	East Kentucky/North Tennessee	25
8	13	West Kentucky	37
9	15,19	South Tennessee/Alabama	11
10	16	Illinois	40
11	17	Indiana	21
12	18	Iowa	17
13	20,21	East Oklahoma/Arkansas	15
14	22,23,24,25	West Oklahoma/Kansas/Missouri/Texas	30
15	26,31	North Colorado/Wyoming	12
16	27,28,32	South Colorado/N.E. New Mexico/Utah	28
17	29,30	West New Mexico/Arizona	15
18	33,34,35	North Dakota/Montana/Washington	11
Total			710

Table C-11
SYMBOLS USED IN DESCRIPTION OF WASHING EQUATIONS

Symbol	Meaning	Symbol	Meaning
A	fractional ash content	O'	lbs organic SO_2 per million Btu
A'	lbs ash per million Btu	P	fractional pyritic sulfur content
$\Delta A'$	fractional reduction in A' through washing	P'	lbs pyritic SO_2 per million Btu
C	cost of coal in dollars per ton	p	fraction of all sulfur that is pyritic
C' million Btu	cost of coal in cents per	$\Delta P'_M$	maximum fractional reduction in P' through washing
$C'_1 - C'_8$	elements of washing cost	S	fractional sulfur content
H	Btu per lb coal	S'	lbs SO_2 per million Btu
H'	lbs of ash-free coal per million Btu	$\Delta S'$	fractional reduction in S' through washing
O	fractional organic sulfur content	$\Delta S'_M$	maximum possible value of $\Delta S'$
		Y	weight yield of washing
		Y'	Btu yield of washing

Note: All coal properties are expressed on a dry basis. The subscript R in the text denotes run-of-mine coal; the subscript W, washed coal.

identities are as follows:

$$A' = \frac{A * 10^6}{H} \tag{19}$$

$$S' = \frac{S * 2 * 10^6}{H} \tag{20}$$

$$H' = \frac{10^6}{H} - A' \tag{21}$$

Identities similar to (20) also exist for the variables O and P. Both pyritic and organic sulfur are present in coal. Therefore,

$$O + P = S \tag{22}$$

$$P = p * S. \tag{23}$$

Also, since physical cleaning reduces only the pyritic sulfur in coal, and organic sulfur is associated with combustible material, these identities hold:

$$O'_w = O'_R \tag{24}$$

$$S'_R - S'_W = P'_R - P'_W. \tag{25}$$

C-3.2.1 Determination of Pyritic Sulfur Fraction

In most regions, the pyritic sulfur fraction in the raw coal was found to be statistically correlated with the sulfur and/or ash content of the run-of-mine coal. The functional form

$$\log (1 - p) = a + b \log (S'_r) + c \log (A'_r) \tag{26}$$

was chosen to test the relationship. The estimated value of p can never exceed 1, but although a value less than zero is theoretically possible it is never attained in practice. One set of observations for each coal was used in carrying out the regression analysis for a region. The pyritic sulfur fraction in East Pennsylvania coals (AUSM Region 1) as a function of the sulfur content is shown in Figure C-6. The estimated values of the coefficients for the 18 regions are in Table C-12.

C-3.2.2 Determination of Maximum Sulfur Reduction

Because maximum sulfur reduction differs from one level of preparation plant to another, three sets of regression analyses are carried out for preparation plant levels 2, 3, and 4. Maximum pyritic sulfur reduction correlates with the run-of-mine pyritic sulfur fraction, allowing the following equation to be fitted:

$$\Delta P'_M = a + bp. \tag{27}$$

The maximum total sulfur reduction is found from

Figure C-6
ESTIMATED PYRITIC SULFUR CONTENT VERSUS SULFUR CONTENT
FOR EAST PENNYSLVANIA COALS

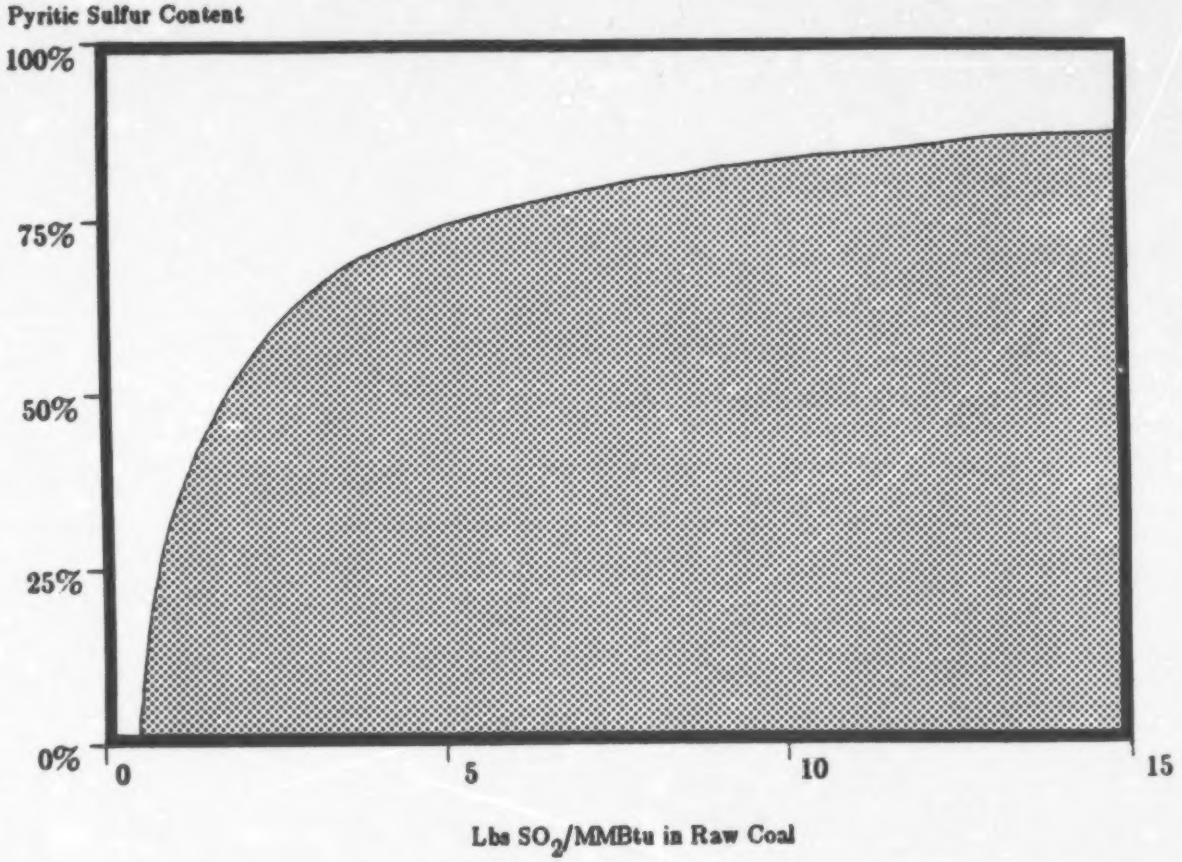


Table C-12
COEFFICIENTS FOR EQUATION 26: PYRITIC SULFUR FRACTION

Region	a	b	(t)	c	(t)	R-sq	N
1	-0.35932	-0.61699	(16.17)	[a]		65.0%	143
2	-0.31616	-0.57277	(8.79)	[a]		56.3%	62
3	-0.14302	-0.82684	(11.55)	[a]		78.3%	39
4	0.1388	-0.2780	(2.37)	-0.3165	(2.61)	29.3%	32
5	-0.18692	-0.54157	(6.56)	[a]		66.2%	24
6	-0.78911	-0.14596	(2.74)	[a]		4.9%	148
7	-0.09177	-0.82905	(11.00)	[a]		84.0%	25
8	0.1114	[a]		-0.44434	(5.65)	47.7%	37
9	-0.24678	-0.65815	(17.72)	[a]		97.2%	11
10	0.3908	[a]		-0.49606	(6.07)	49.2%	40
11	-0.0076	[a]		-0.4148	(2.61)	26.4%	21
12	-1.1552	[a]		[a]			17
13	-0.6539	-0.6641	(4.47)	0.2129	(2.02)	62.5%	15
14	0.1802	-0.64586	(9.37)	[a]		75.8%	30
15	-0.27398	[a]		[a]			12
16	-0.37346	-0.37765	(5.32)	[a]		52.1%	28
17	-0.00363	-0.14215	(3.50)	[a]		48.5%	15
18	-0.4423	-0.8712	(2.86)	[a]		47.5%	11

[a] Coefficient not significant at the 95 percent level.

$$\Delta S'_M = p \ \Delta P'_M \, . \qquad (28)$$

Again one set of observations for each coal was appropriate. The resulting coefficients are in Tables C-13, C-14, and C-15. Sulfur reductions in excess of $\Delta S'_M$ are considered physically infeasible.

Table C-13
COEFFICIENTS FOR EQUATION 37: MAXIMUM SULFUR REMOVAL, LEVEL 2 CLEANING

Region	a	b	(t)	R-sq	N
1	0.09466	0.28369	(4.84)	14.3%	143
2	0.39911	[a]			62
3	0.25031	[a]			37
4	0.39092	[a]			32
5	-0.01439	0.9024	(4.78)	50.9%	24
6	0.37898	[a]			148
7	0.32580	[a]			25
8	0.1458	0.4638	(2.52)	15.4%	37
9	0.21660	[a]			11
10	0.12491	0.4791	(3.44)	23.7%	40
11	0.1220	0.4612	(2.65)	27.0%	21
12	0.41848	[a]			17
13	-0.04134	0.3932	(3.16)	43.4%	15
14	0.06099	0.45633	(5.01)	49.1%	28
15	0.34663	[a]			12
16	-0.02795	0.5810	(2.36)	17.7%	28
17	-0.17869	1.4237	(4.31)	58.8%	15
18	0.50171	[a]			11

[a] Coefficient not significant at the 95 percent level.

Table C-14
COEFFICIENTS FOR EQUATION 27: MAXIMUM SULFUR REMOVAL, LEVEL 3 CLEANING

Region	a	b	(t)	R-sq	N
1	0.21075	0.57507	(8.40)	33.4%	143
2	0.41168	0.3190	(2.67)	10.8%	61
3	0.32237	0.2967	(2.13)	11.5%	37
4	0.60272	a			32
5	-0.00562	1.4665	(6.04)	62.4%	24
6	0.60161	a			148
7	0.26180	0.4082	(2.92)	27.0%	25
8	0.1644	0.7732	(4.32)	34.8%	37
9	0.0922	0.7171	(2.16)	34.2%	11
10	0.15195	0.7950	(4.61)	35.9%	40
11	0.0645	0.8464	(4.23)	48.5%	21
12	0.3743	0.3763	(2.14)	23.4%	17
13	-0.06989	0.7054	(3.85)	53.3%	15
14	0.19301	0.5241	(3.83)	36.0%	28
15	0.40458	a			10
16	0.22912	a			27
17	-0.2003	1.6938	(3.71)	51.5%	15
18	0.72358	a			11

[a] Coefficient not significant at the 95 percent level.

C-3.2.3 Determination of Ash Content of Washed Coal

The ash content of the washed coal is given by the identity

$$A'_w = A'_R(1 - \Delta A') \tag{29}$$

with the following regression equation for $\Delta A'$ being tested:

$$log(\frac{\Delta A'}{1 - \Delta A'}) =$$

$$A + b \log(\frac{\Delta S'}{p - \Delta S'}) + c \log(S'_R) + d \log(A'_R) + e \log(H'_R) \tag{30}$$

This formulation has the satisfactory property that $\Delta A' \rightarrow 1$ as $\Delta S' \rightarrow p$, the pyritic sulfur fraction. Figure C-7 shows a plot of $\Delta A'$ *vs* $\Delta S'$ for a typical East Pennsylvania coal.

The values of the coefficients in the equation were determined by regression analysis on data obtained by washing every coal in a Level 4 plant so as to remove sulfur in 5 percent increments (i.e., $\Delta S'$ = 5%, 10%, 15%, and so forth) up to the maximum possible extent. The results for all the coals in each region were pooled before the analyses were performed. The values found for the coefficients are shown in Table C-16. A_w may be determined from A'_w once H_w is determined (see Section 3.2.4).

C-3.2.4 Determination of Btu Content of Washed Coal

As noted in Section 2.7, the Btu contents of the USBM washed samples were estimated from the regression equation shown in Equation 18. Therefore, for each coal, the following identity must hold:

$$H_w + K(A_w + 0.3\ P_w + 0.5\ O_w) = H_R + K(A_R + 0.3\ P_R + 0.5\ O_R). \tag{31}$$

The values of K [11] proved to have a weak correlation with the properties of the seam sample, and the following regression equation was found to be satisfactory for testing the relationship:

$$\frac{1}{K} = 10^{-4}(a + b\ S_R^{1/2} + cA_R^{1/2} + dH_R^{1/2}). \tag{32}$$

Table C-15
COEFFICIENTS FOR EQUATION 27: MAXIMUM SULFUR REMOVAL, LEVEL 4 CLEANING

Region	a	b	(t)	R-sq	N
1	0.20229	0.81522	(10.75)	46.5%	143
2	0.45576	0.4056	(3.25)	15.2%	61
3	0.3739	0.4943	(3.17)	23.3%	35
4	0.4283	0.4473	(2.78)	21.1%	31
5	-0.02856	1.7471	(6.60)	66.4%	24
6	0.70139	[a]			145
7	0.30062	0.4778	(2.76)	24.8%	25
8	0.16422	0.9208	(5.92)	50.8%	36
9	0.1001	0.8969	(2.53)	41.6%	11
10	0.21162	0.8118	(4.89)	38.7%	40
11	0.0299	0.9956	(3.76)	42.7%	21
12	0.3288	0.5201	(2.40)	27.7%	17
13	-0.1259	1.0526	(4.61)	62.0%	15
14	0.17278	0.7126	(4.98)	48.8%	30
15	0.4940	[a]			12
16	0.0667	0.7853	(2.13)	15.4%	27
17	-0.1959	1.7594	(3.17)	43.7%	15
18	0.75624	[a]			11

[a] Coefficient not significant at the 95 percent level.

Figure C-7
ASH REDUCTION VERSUS SULFUR REDUCTION FOR A TYPICAL PENNSYLVANIA COAL

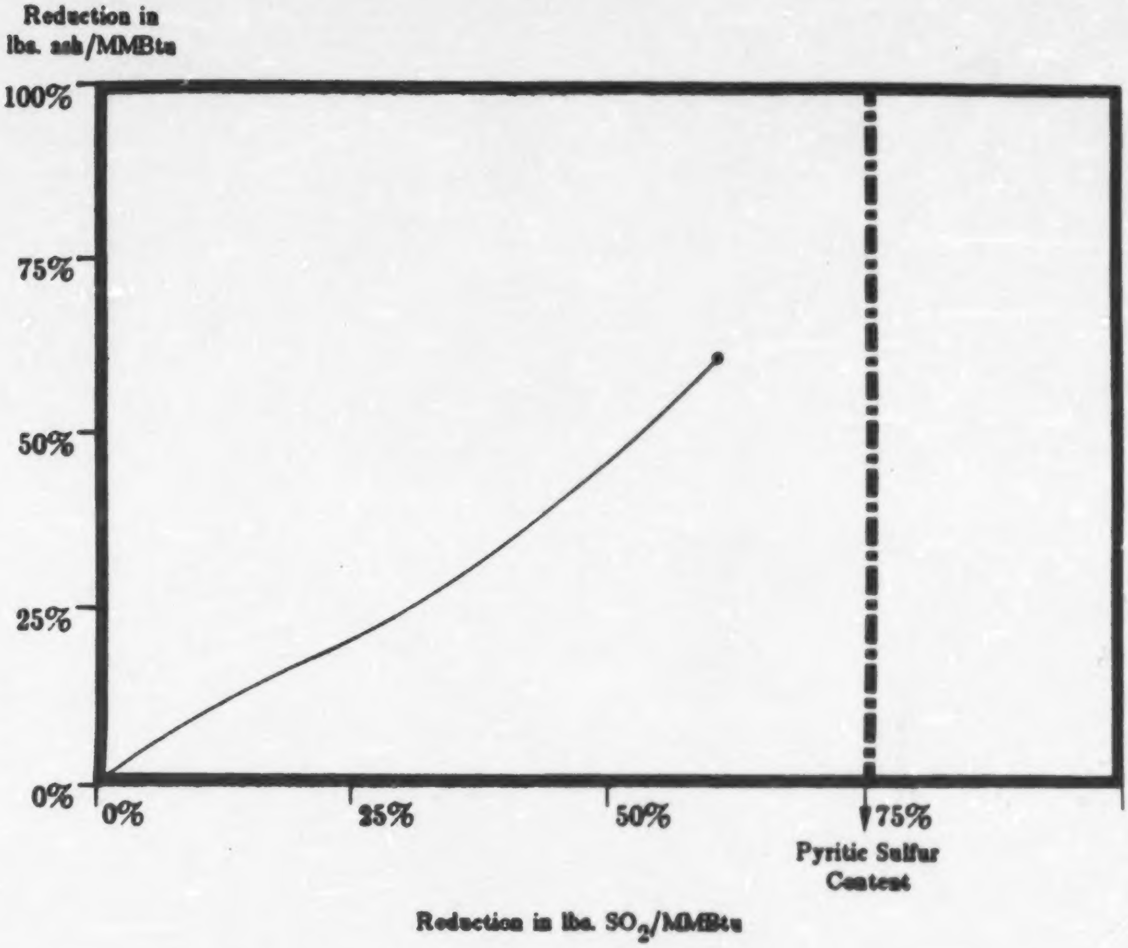


Table C-16
COEFFICIENTS FOR EQUATION 30: ASH CONTENT

Region	a	b	c	d	e	R-sq	N
1	-17.87	0.789	0.129	0.535	3.747	80.6%	1357
		(70.02)	(4.61)	(15.05)	(5.18)		
2	7.45	0.810	-0.233	0.654	-2.137	76.7%	549
		(39.60)	(4.85)	(14.31)	(2.03)		
3	18.67	0.811	[a]	0.708	-5.039	82.9%	349
		(38.86)		(9.67)	(2.83)		
4	-50.98	0.863	[a]	0.751	11.628	87.4	284
		(40.12)		(12.80)	(11.79)		
5	-0.94	0.834	-2.052	0.794	[a]	85.6	63
		(13.86)	(9.37)	(8.75)			
6	7.78	0.839	0.200	0.375	-2.230	81.4%	1325
		(73.38)	(5.57)	(10.82)	(3.29)		
7	-0.71	0.947	-0.288	0.436	[a]	69.5	124
		(15.81)	(2.99)	(3.80)			
8	-1.10	0.914	-0.921	1.032	[a]	88.3%	321
		(45.09)	(7.79)	(16.12)			
9	-39.48	0.876	[a]	[a]	9.445	80.1%	45
		(12.86)			(7.32)		
10	5.29	0.899	-0.523	1.009	-1.704	91.3%	305
		(52.58)	(10.46)	(16.79)	(3.35)		
11	-2.89	0.790	0.771	0.338	[a]	81.0%	158
		(21.20)	(10.30)	(2.27)			
12	23.71	0.832	0.581	[a]	-5.990	90.5%	155
		(36.62)	(8.43)		(4.44)		
13	35.09	0.717	[a]	1.798	-9.317	80.9%	57
		(10.39)		(9.68)	(5.55)		
14	37.70	0.888	0.331	0.544	9.433	78.4%	204
		(24.21)	(2.08)	(6.29)	(7.36)		
15	31.10	0.398	[a]	0.718	-7.644	55.2%	31
		(4.29)		(2.58)	(2.71)		
16	-25.33	0.768	-1.069	[a]	5.915	80.5%	43
		(10.89)	(7.65)		(3.52)		
17	-3.23	0.767	-1.061	1.058	[a]	75.2%	28
		(7.40)	(2.57)	(4.05)			
18	91.63	0.628	0.431	1.253	-22.012	75.8%	94
		(14.01)	(2.05)	(2.55)	(7.83)		

[a] Coefficient is not significant at the 95 percent level.

Note: t-statistics are in parentheses.

The results of the analysis are shown in Table C-17. In many regions, b, c and d are all zero - i.e., no significant correlation between K and the seam characteristics of coal was found.

Table C-17
COEFFICIENTS FOR EQUATION 32: BTU CONTENT CONSTANT

Region	a	b	c	d	R-sq	N
1	59.69	*	0.087 (2.95)	*	3.5%	136
2	61.55	*	*	*		61
3	59.94	*	*	*		37
4	64.13	*	*	*		32
5	60.49	*	*	*		16
6	93.89	*	0.141 (2.61)	-0.455 (2.31)	6.0%	148
7	62.28	*	*	*		22
8	-40.51	*	-0.330 (2.24)	1.630 (2.35)		37
9	64.16	*	*	*		9
10	64.86	*	*	*		40
11	77.53	*	-1.137 (2.34)	*	22.4%	21
12	237.61	*	*	-2.385 (2.68)	32.4%	17
13	59.21	*	*	*		8
14	1.98	*	*	0.832 (3.11)	28.7%	26
15	70.47	*	*	*		10
16	-11.69	*	*	1.047 (2.02)	18.5%	20
17	-154.31	-5.153 (2.00)	*	1.047 (2.97)	66.7%	10
18	59.46	6.402 (2.41)	*	*	42.0%	10

* Coefficient is not significant at the 95 percent level.

Note: t-statistics are in parentheses.

Equation 31 cannot be used directly to calculate H_w, even if we know K, because A_w, P_w, and O_w remain unknown until H_w is found. The following manipulation is necessary. Substituting Equations 19 and 20 into 31 gives:

$$H_w\left(1 + \frac{K\,A_w^1}{10^6} + \frac{0.3\,P_w^1\,K}{2 * 10^6} + \frac{0.5\,O_w^1\,K}{2 * 10^6}\right)$$

$$= H_R\left(1 + \frac{K\,A_R^1}{10^6} + \frac{0.3\,P_R^1\,K}{2 * 10^6} + \frac{0.5\,O_R^1\,K}{2 * 10^6}\right) \tag{33}$$

Then using Equations 22 and 23 and rearranging gives:

$$H_w = H_R * \frac{(\frac{10^6}{K} + A_R^1 + S_R^1(0.25 - 0.1p))}{(\frac{10^6}{K} + A_w^1 + S_w^1(0125 - 0.1p))}. \tag{34}$$

All the terms on the right-hand side of Equation 34 are now known quantities.

C-3.2.5 Determination of Btu Yield

The Btu yield of a washing process is the fraction of the Btu's in the raw coal that is recovered in the washed coal. The following regression equation for y' was tested:

$$\log(1-Y') =$$

$$a + b\,\log\left(\frac{\Delta S'}{p-\Delta S'}\right) + c\,\log(S_R') + d\,\log(A_R') + e\,\log(H_R'). \tag{35}$$

This has the satisfactory property that Y' falls away rapidly as $\Delta S' \rightarrow p$. The coefficients in this equation were determined by pooling a series of results from each coal in a region prior to performing the regression analyses, as with the ash reduction equation. Three different regression analyses were carried out for each region because the process yield is a function of the preparation plant level. The values of the coefficients found are shown in Tables C-18, C-19, and C-20. Y' is plotted against $\Delta S'$ for a typical East Pennsylvania coal in Figure C-8.

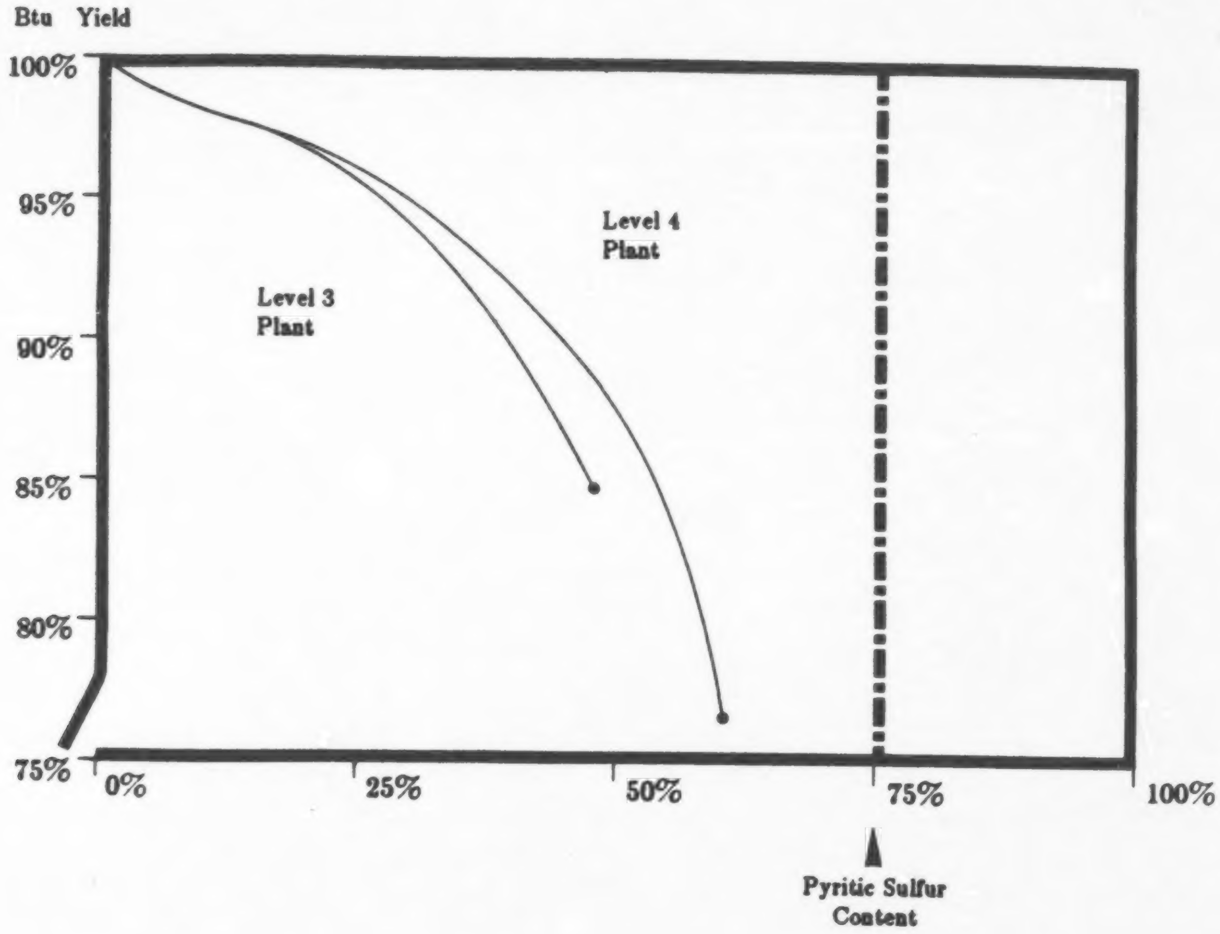
Table C-18
COEFFICIENTS FOR EQUATION 35: LEVEL 2 PROCESS YIELDS

Region	a	b	c	d	e	R-sq	N
1	-40.958	0.81860	a	0.22289	9.060	44.2%	508
		(18.34)		(2.65)	(5.43)		
2	-3.3826	0.73402	a	0.32657	a	37.1%	306
		(12.99)		(3.48)			
3	-2.8682	0.81500	0.7000	a	a	49.4%	116
		(10.30)	(5.00)				
4	-43.68	1.0092	-0.5290	0.4421	9.814	41.8%	154
		(10.00)	(2.28)	(2.29)	(2.51)		
5	-3.5992	1.2147	-1.2668	0.8145	a	66.0%	36
		(6.41)	(2.72)	(4.10)			
6	-3.5681	0.99243	a	0.56547	a	50.4%	706
		(25.84)		(7.83)			
7	-71.54	1.0909	0.5938	a	16.200	54.5%	76
		(7.89)	(3.45)		(3.66)		
8	-62.556	0.99369	a	a	14.111	68.2%	188
		(19.35)			(6.52)		
9	-135.48	1.0155	a	1.5298	31.118	76.5%	22
		(4.99)		(5.35)	(4.60)		
10	-2.89757	0.87995	a	a	a	47.4%	180
		(12.66)					
11	-2.7948	1.0495	0.9014	-0.5706	a	59.6%	100
		(10.30)	(5.84)	(2.08)			
12	-44.65	0.8793	a	0.8122	9.334	77.8%	95
		(14.73)		(4.83)	(3.52)		
13	23.41	1.2118	1.3763	1.3568	-6.889	83.7%	22
		(6.13)	(2.03)	(4.21)	(5.16)		
14	48.895	0.91675	a	0.5649	-12.405	53.3%	118
		(10.37)		(3.65)	(7.75)		
15	-3.7511	0.7381	a	a	a	19.5%	20
		(2.09)					
16	-81.68	1.4318	-1.8254	a	18.788	79.1%	22
		(5.52)	(5.00)		(3.88)		
17	-5.238	1.1810	-3.606	1.3020	a	67.7%	21
		(5.23)	(3.28)	(3.10)			
18	102.05	1.01044	0.8720	1.9635	-25.286	72.5%	63
		(10.99)	(2.66)	(2.56)	(6.49)		

[a] Coefficient not significant at the 95 percent level.

Note: t-statistics are in parentheses.

Figure C-8
BTU YIELD VERSUS SULFUR REDUCTION FOR A TYPICAL PENNSYLVANIA COAL



% Sulfur Reduction

C-3.3 Equations for the Cost of Washed Coal

Five components of the cost of coal cleaning are generated when the coal preparation plant model is run, as indicated in Section C-2.7. The results for each preparation plant level and supply region are pooled and, for each component, the following regression equation was tested:

$$C = A * (Y)^{-b} \tag{36}$$

where Y is the process weight yield derived from the Btu yield as follows:

$$Y = Y^1 * \frac{H_R}{H_w}. \tag{37}$$

These regression analyses proved extremely satisfactory, with all the R^2 in excess of 99 percent. The results for preparation levels 2, 3, and 4 are shown in Tables C-21, C-22, and C-23, with the five columns corresponding to the five cost elements in Section C-2.7.

C-4. Using the Equations to Wash the AUSM Characteristic Coals

C-4.1 Overview

Before the use of the equations is described, two caveats are in order. First, coal preparation today is not used primarily as a method of sulfur removal. Instead, it is used to reduce the ash content, and hence increase the Btu content, of run-of-mine coals in order to reduce transportation costs and meet fuel qualities specified by the user. As a result, the washability equations may indicate that more sulfur removal is possible in certain types of coal than is usual under current practices. Moreover, any indication by the equations that a particular level of sulfur removal is possible should not be construed to mean that the degree of quality enhancement is economical. All that these equations can do is deliver a cost for washed coal; whether washing is economically justified or not can be determined only in the broader context of the AUSM coal supply module.

The second caveat concerns the large degree of statistical variation in the washabilities of coals, even those from the same region with apparently similar run-of-mine properties. Consequently, these equations cannot be used to assess the effects of washing on any particular coal, nor can the validity of the equations be confirmed or disproved by the washed properties of individual coals. This problem is inherent in any statistical analysis of a set of data that is characterized by a large degree of variance.

Table C-19

COEFFICIENTS FOR EQUATION 35: LEVEL 3 PROCESS YIELDS

Region	a	b	c	d	e	R-sq	N
1	-53.543	0.92621 (43.57)	0.12014 (2.82)	0.15231 (2.83)	12.016 (10.78)	66.4%	1063
2	-3.4735	0.88423 (22.88)	a	0.40630 (5.46)	a	53.8%	474
3	-33.61	0.85743 (20.04)	0.54708 (5.78)	a	7.317 (2.82)	64.4%	253
4	-58.45	1.06502 (17.10)	a	a	13.342 (5.34)	56.6%	240
5	-60.20	1.0145 (9.39)	-1.3890 (4.24)	0.7656 (5.72)	13.408 (2.33)	74.2%	55
6	-26.103	0.99990 (40.59)	a	0.60847 (9.37)	5.261 (4.26)	61.4%	1128
7	-50.31	1.07858 (11.25)	0.5614 (3.87)	a	11.151 (3.15)	62.0%	107
8	-68.676	0.99091 (29.34)	a	a	15.523 (9.20)	76.7%	279
9	-89.20	0.9246 (32.15)	0.4685 (2.67)	1.4982 (4.16)	19.937 (6.81)	81.8%	37
10	-2.5012	0.98812 (22.64)	-0.2261 (2.11)	a	a	65.6%	274
11	-4.2308	0.99291 (14.73)	0.8589 (7.82)	a	a	67.6%	144
12	-29.547	0.91021 (21.53)	a	1.0232 (6.99)	5.659 (2.49)	81.9%	143
13	23.05	1.1562 (8.40)	1.5190 (5.67)	1.9837 (6.61)	-7.296 (2.50)	82.9%	40
14	37.476	1.02366 (17.46)	0.4489 (2.49)	0.4887 (3.93)	-9.878 (5.46)	68.4%	172
15	-3.6614	1.0037 (4.25)	a	a	a	42.0%	27
16	-75.30	1.2654 (7.14)	-1.9103 (6.12)	a	17.241 (4.49)	75.0%	37
17	-6.0601	1.0878 (6.13)	-3.2300 (3.27)	1.4965 3.91)	a	68.8%	26
18	86.08	0.85460 (14.51)	0.7122 (2.64)	1.7416 (2.78)	-21.578 (6.08)	74.9%	91

[a] Coefficient not significant at the 95 percent level.

Note: t-statistics are in parentheses.

Table C-20
COEFFICIENTS FOR EQUATION 35: LEVEL 4 PROCESS YIELDS

Region	a	b	c	d	e	R-sq	N
1	-59.424	0.82754 (53.78)	0.15043 (3.95)	0.10571 (2.18)	13.3875 (13.57)	70.5%	1365
2	-18.473	0.89523 (28.20)	a	0.40916 (5.77)	3.545 (2.25)	60.8%	549
3	-37.284	0.81268 (26.71)	0.44684 (.532)	a	8.198 (3.70)	68.8%	345
4	-83.27	1.04005 (20.98)	-0.3281 (2.02)	a	19.341 (7.08)	62.5%	284
5	-4.3524	0.95280 (10.83)	-1.0107 (3.15)	0.8315 (6.26)	a	73.8%	63
6	-31.860	1.01639 (49.85)	a	0.63986 (10.75)	6.592 (5.79)	67.6%	1325
7	-42.88	1.05105 (14.08)	0.6032 (4.63)	a	9.364 (2.98)	68.1%	124
8	-71.285	0.99877 (35.11)	a	a	16.129 (10.44)	80.4%	321
9	-110.68	0.9716 (8.79)	a	1.6752 (7.41)	25.074 (4.55)	78.5%	45
10	-2.5135	0.96872 (25.66)	-0.2614 (2.59)	a	a	68.7%	305
11	-4.2720	0.96080 (17.20)	0.8418 (8.40)	a	a	70.2%	158
12	-25.863	0.85047 (24.21)	a	1.0916 (8.69)	4.733 (2.39)	84.3%	155
13	15.55	1.13196 (12.03)	1.5520 (6.83)	2.1527 (7.65)	-5.663 (2.30)	82.9%	57
14	36.975	1.05135 (22.12)	0.4091 (2.56)	0.5022 (4.48)	-9.751 (5.87)	74.3%	204
15	-3.7192	1.0631 (5.77)	a	a	a	53.4%	31
16	-80.38	1.1620 (9.12)	-1.7362 (6.88)	a	18.352 (6.05)	80.2%	43
17	-6.9450	0.9900 (7.40)	-3.2827 (4.07)	1.7650 (5.24)	a	77.4%	28
18	83.96	0.73650 (13.33)	0.6404 (2.47)	2.0169 (3.33)	-21.242 (6.13)	71.9%	94

[a] Coefficient not significant at the 95 percent level.

Note: t-statistics are in parentheses.

Table C-21
COEFFICENTS FOR EQUATION 36: LEVEL 2 CLEANING

Region		Cost Factor 1	2	3	4	5
1	a	0.619093	3.807487	0.097906	0.525000	0.080100
	b	2.719581	1.294269	3.358841	0.000000	0.000000
2	a	0.627246	3.830741	0.099753	0.525000	0.080100
	b	2.553919	1.216758	3.122499	0.000000	0.000000
3	a	0.620619	3.809429	0.098322	0.525000	0.080100
	b	2.688432	1.276783	3.309514	0.000000	0.000000
4	a	0.628632	3.834002	0.100048	0.525000	0.080100
	b	2.501458	1.197830	3.046919	0.000000	0.000000
5	a	0.610605	3.777676	0.096120	0.525000	0.080100
	b	2.746438	1.310856	3.390750	0.000000	0.000000
6	a	0.623061	3.820444	0.098791	0.525000	0.080100
	b	2.647161	1.256517	3.255952	0.000000	0.000000
7	a	0.620214	3.806880	0.098214	0.525000	0.080100
	b	2.682012	1.280424	3.300137	0.000000	0.000000
8	a	0.624267	3.824235	0.099037	0.525000	0.080100
	b	2.644349	1.258974	3.251975	0.000000	0.000000
9	a	0.619628	3.803539	0.098093	0.525000	0.080100
	b	2.522106	1.211865	3.070637	0.000000	0.000000
10	a	0.616793	3.804009	0.097344	0.525000	0.080100
	b	2.881051	1.359611	3.590568	0.000000	0.000000
11	a	0.616725	3.804101	0.097357	0.525000	0.080100
	b	2.771288	1.308182	3.434445	0.000000	0.000000
12	a	0.619425	3.812396	0.097979	0.525000	0.080100
	b	2.814493	1.325481	3.495939	0.000000	0.000000
13	a	0.612761	3.781188	0.096629	0.525000	0.080100
	b	2.608272	1.249779	3.191600	0.000000	0.000000
14	a	0.624927	3.822604	0.099294	0.525000	0.080100
	b	2.628170	1.249591	3.226952	0.000000	0.000000
15	a	0.606542	3.768347	0.095086	0.525000	0.080100
	b	2.966041	1.409620	3.713718	0.000000	0.000000
16	a	0.609395	3.769458	0.095913	0.525000	0.080100
	b	2.436776	1.183646	2.940794	0.000000	0.000000
17	a	0.603542	3.755819	0.094592	0.525000	0.080100
	b	3.194965	1.529770	4.027247	0.000000	0.000000
18	a	0.614737	3.797737	0.096790	0.525000	0.080100
	b	2.516324	1.215409	3.070530	0.000000	0.000000

Table C-22
COEFFICENTS FOR EQUATION 36: LEVEL 3 CLEANING

Region	Cost Factor 1	2	3	4	5
1 a	0.999228	5.799439	0.162891	0.553300	0.084400
b	1.849435	0.961736	2.204369	0.000000	0.000000
2 a	0.992424	5.640730	0.163680	0.553300	0.084400
b	1.737241	0.937431	2.031674	0.000000	0.000000
3 a	1.014197	5.844519	0.166163	0.553300	0.084400
b	1.774604	0.936484	2.097587	0.000000	0.000000
4 a	0.989138	5.633253	0.162919	0.553300	0.084400
b	1.723866	0.930752	2.012801	0.000000	0.000000
5 a	0.950106	5.536774	0.153993	0.553300	0.084400
b	2.087513	1.077845	2.527447	0.000000	0.000000
6 a	0.981073	5.605111	0.161227	0.553300	0.084400
b	1.785620	0.958533	2.097084	0.000000	0.000000
7 a	0.966599	5.549427	0.158250	0.553300	0.084400
b	1.865744	0.988924	2.208694	0.000000	0.000000
8 a	0.980754	5.635006	0.160683	0.553300	0.084400
b	1.842955	0.979263	2.180524	0.000000	0.000000
9 a	0.970736	5.575559	0.158975	0.553300	0.084400
b	1.817230	0.973766	2.138235	0.000000	0.000000
10 a	0.976264	5.620233	0.159683	0.553300	0.084400
b	1.906995	1.002762	2.272080	0.000000	0.000000
11 a	0.968148	5.573740	0.158310	0.553300	0.084400
b	1.840367	0.966753	2.178973	0.000000	0.000000
12 a	0.972584	5.597817	0.159156	0.553300	0.084400
b	1.928285	1.008232	2.299635	0.000000	0.000000
13 a	0.992660	5.836921	0.160442	0.553300	0.084400
b	1.915506	0.971504	2.307750	0.000000	0.000000
14 a	0.992665	5.627650	0.163967	0.553300	0.084400
b	1.734826	0.943140	2.025212	0.000000	0.000000
15 a	0.957102	5.528801	0.155858	0.553300	0.084400
b	1.789916	0.0970438	2.100011	0.000000	0.000000
16 a	0.959213	5.550346	0.156074	0.553300	0.084400
b	1.796905	0.966591	2.114030	0.000000	0.000000
17 a	0.939896	5.485396	0.152051	0.553300	0.084400
b	2.259259	1.169901	2.761695	0.000000	0.000000
18 a	0.944334	5.497393	0.153078	0.553300	0.084400
b	2.075783	1.069136	2.509897	0.000000	0.000000

Table C-23
COEFFICENTS FOR EQUATION 36: LEVEL 4 CLEANING

Region	*Cost Factor*				
	1	2	3	4	5
1 a	1.311987	7.560420	0.213786	0.892600	0.136200
b	1.449800	0.786710	1.694020	0.000000	0.000000
2 a	1.264446	7.173209	0.207515	0.892600	0.136200
b	1.480717	0.818026	1.720064	0.000000	0.000000
3 a	1.342800	7.659779	0.220473	0.892600	0.136200
b	1.381248	0.763802	1.594268	0.000000	0.000000
4 a	1.261385	7.151501	0.207034	0.892600	0.136200
b	1.455064	0.807206	1.683483	0.000000	0.000000
5 a	1.226441	7.139975	0.197613	0.892600	0.136200
b	1.708192	0.887857	2.058453	0.000000	0.000000
6 a	1.266483	7.181898	0.207871	0.892600	0.136200
b	1.451457	0.811421	1.677493	0.000000	0.000000
7 a	1.243437	7.017013	0.204404	0.892600	0.136200
b	1.453187	0.821888	1.673820	0.000000	0.000000
8 a	1.258117	7.202090	0.205360	0.892600	0.136200
b	1.518040	0.827682	1.776286	0.000000	0.000000
9 a	1.260146	7.219057	0.205559	0.892600	0.136200
b	1.495445	0.819776	1.743206	0.000000	0.000000
10 a	1.245986	7.185170	0.202425	0.892600	0.136200
b	1.628472	0.861377	1.939243	0.000000	0.000000
11 a	1.239860	7.145401	0.201333	0.892600	0.136200
b	1.559965	0.821004	1.846315	0.000000	0.000000
12 a	1.242446	7.141457	0.202131	0.892600	0.136200
b	1.632825	0.868945	1.943019	0.000000	0.000000
13 a	1.314118	7.535595	0.214474	0.892600	0.136200
b	1.373234	0.770262	1.580557	0.000000	0.000000
14 a	1.284552	7.186861	0.212623	0.892600	0.136200
b	1.385056	0.792678	1.581363	0.000000	0.000000
15 a	1.254577	7.248784	0.203298	0.892600	0.136200
b	1.413192	0.793022	1.628743	0.000000	0.000000
16 a	1.230788	7.113757	0.199200	0.892600	0.136200
b	1.560262	0.857383	1.832549	0.000000	0.000000
17 a	1.228674	7.113959	0.198681	0.892600	0.136200
b	1.623500	0.891422	1.919888	0.000000	0.000000
18 a	1.230075	7.220661	0.197162	0.892600	0.136200
b	1.812131	0.918962	2.223424	0.000000	0.000000

The equations can be used only to predict "typical" or "average" washabilities of coals from particular regions.

Referring to the triangular matrix format in Figure C-1, it is necessary to derive the properties of a characteristic coal (as defined by Pechan [2]) that has been washed from a sulfur category on the diagonal to a lower (off-diagonal) sulfur category. The seam-quality sulfur content of the coal, S_R^1, expressed in pounds of SO_2 per million Btu equivalent, is known from the Pechan analysis. The washed sulfur content, S_w^1, is set at the midpoint of the appropriate interval as defined in Table C-1. The fractional sulfur removal is then given by:

$$\Delta S^1 = 1 - \frac{S_w^1}{S_R^1}. \tag{38}$$

Since three types of preparation plant (levels 2, 3, and 4 as defined in Section C-2.1) are available to remove sulfur from coal, the washing equations are exercised three times (for a particular washing step). The preparation plant level that will result in the lowest cost (in dollars per million Btu) for the washed coal is then selected. Referring to Equation 2 (Section C-1.2), it can be seen that an estimate of the cost of run-of-mine coal is required to do this. The estimate is made using the work of Green and Michelson [12].

The tradeoff between the different levels of preparation plant arises because the high levels of preparation plant can achieve a given level of sulfur removal at a higher process yield than a low-level preparation plant can. However, the capital and operating costs are higher. Where low levels of sulfur removal are required and process yields are high in any case, lower level preparation is most economical. With a high sulfur removal, however, the effect of differing process yields on the cost of input coal tends to outweigh the capital and operating cost difference.

C-4.2 Physical Washing Equations

The first step is to test whether the requested sulfur removal is physically possible for the particular preparation plant level under consideration. To do this, the pyritic sulfur fraction of the coal is first estimated from Equation 26 and then used via Equations 27 and 28 to arrive at a maximum sulfur removal for the particular coal and preparation level. If the requested removal is less than or equal to the maximum removal, the process is physically feasible. Note that no sulfur removal is considered possible for sub-bituminous coals and lignite because the fact that these coals accumulate large quantities of moisture during washing makes anything other than a minimum degree of preparation unattractive.

The next step is to calculate the coal and Btu contents of the washed coal using Equations 30, 32, and 34. Finally, Equation 35 is used to determine the Btu yield of the washing processes.

C-4.3 Washing Coal Equations

Since the cost equations use the weight yield as the independent variable, this parameter must be calculated from the Btu yield using Equation 37. However, the weight yield obtained is that required to get from seam-quality coal to a superior product, identified as Y_w^1 in Equation 3. The actual preparation plant yield, Y^1, is obtained by multiplying Y_w^1 by Y_B, the basic preparation yield required to get from run-of-mine coal to seam-quality coal. (The basic preparation assumptions are detailed in Section C-4.4, below).

The preparation plant yield, Y_w, is put into the washing cost equations of the type shown in Equation 36 to obtain the five cost elements listed in Section C-2.7. It is then necessary to combine these into a single cost expressed in dollars per ton of raw coal. The results depends on the financial assumptions made. These are summarized in Table C-24.

Table C-24
FINANCIAL ASSUMPTIONS USED TO DERIVE WASHING COSTS

Inflation	7%	Real after-tax rate of return on equity	6.1%
Real escalation of capital	0.5%	Real rate of cost of debt	1.5%
Real escalation of labor	1%	Debt ratio	30%
Real escalation of power and supplies	0%	Depletion allowance (% of gross profits)	50%
Corporate tax rate	50%		

Capital charges are annualized as follows. It can be shown that the present value of the capital charges associated with a capital investment of K dollars in the year prior to startup is given by:

$$PW = \frac{(1 + d)K - T^1 \overline{D}_T}{1 - T^1} \tag{39}$$

where d is the nominal discount rate given by:

$$d = (1 - T^1)\, D\, r_d + (1 - D) r_e \tag{40}$$

and where r_d = nominal return on debt

r_e = nominal return on equity

D = debt ratio.

T^1 is an effective tax rate that has been adjusted from the corporate tax rate T to allow for a depletion allowance of 50 percent on gross profits (see Chapter 4, Section 4.2.1.2):

$$T^1 = T * 0.5. \tag{41}$$

PV is the present value function for a constant stream of revenues:

$$PV(d,L) = \frac{(1 + d)(1 - \frac{1}{(1 + d)} L)}{d} \tag{42}$$

The present worth of the capital charges may be converted into a constant stream of *real* revenues as follows:

$$\overline{K} = PW / PV(r, L) \tag{43}$$

where r is the real after-tax discount rate given by:

$$r = \frac{d - i}{1 + i} \tag{44}$$

where i is the inflation rate.

It is assumed that working capital is rolled over annually and has to be replaced at prices that increase through inflation. Therefore, the real annualized charge associated with working capital is:

$$\overline{WC} = WC * (D * r_d) + \frac{1 - D)r_e}{1 - T^1} \tag{45}$$

The allowance for administration, property taxes, and insurance is proportional to the initial capital cost:

$$AV = a * K \tag{46}$$

where a is the annual ad valorem charge. The present worth of the charges (which are assumed to remain constant in current dollars) is

$$PW = a * K * PV(d,L) \tag{47}$$

which converts to a constant stream of real dollars as follows:

$$\overline{AV} = \frac{a * K * PV(d,L)}{PV(r,L)} \tag{48}$$

The total capital charges are given by:

$$\overline{CC} = \overline{K} + \overline{WC} + \overline{AV} \tag{49}$$

The total cost of coal preparation in dollars per raw ton is given by adding the capital charges to the levelized operational costs and dividing by the annual plant input:

$$C_c = \frac{O + \overline{CC}}{T * H} \tag{50}$$

where O is the annual levelized operating cost, T is the plant output in tons per hour, and H is the annual operating hours. It should be noted that costs in Tables C-5 and C-6 are as of mid-1978. Using the standard chemical engineering cost index, these costs are increased by 21 percent to bring them to 1980 levels.

The preparation plant yield, Y_w, and the washing cost, C_c, are placed in the off-diagonal elements of the triangular matrix.

C-4.4 Basic Preparation Assumptions

Assumptions are required to establish the costs of preparing run-of-mine coal in order to bring it up to seam quality and to adjust the process yields of deeper washing processes. Broadly, it is assumed that eastern bituminous coal is washed to bring it up to seam quality, but that all other coals need only be crushed, broken, and screened. The precise assumptions are:

1. *Deep Coal*

a. All bituminous coals in AUSM supply regions 1-24 and 35, plus sub-bituminous coals in region 35, receive Level 2 preparation, with an 80 percent process yield.

b. All other coals receive Level 1 preparation (crushing and screening) witn a 98 percent yield.

2. *Surface Coal*

a. All bituminous coals in AUSM supply regions 1-6, 9, 13, 16-24, and 35, plus sub-bituminous coals in region 35, receive Level 2 preparation, with an 80 percent process yield.

b. All other coals receive Level 1 preparation (crushing and screening) with a 98 percent yield.

These yields are fed into washing Equation 36 for the appropriate preparation plant level, and the financial analysis in Section C-4.3 is carried out to obtain the basic preparation cost. The costs and yields are placed in the on-diagonal terms of the triangular matrices.

C-5. Mandatory Washing

The triangular matrix formulation provides a suitable framework within which to implement mandatory washing scenarios in which a degree of sulfur removal through washing is required from suitable coals. This can be achieved by "blocking out" certain on-diagonal elements, or elements close to the diagonal, of the triangular matrices.

Mandatory washing has been implemented by postulating a washing "regulation" that focuses on the expected degree of sulfur removal from coals. However, the sulfur contents of many coals can be reduced only at a large cost, due principally to the low process yields involved. Therefore, to avoid incurring excessive abatement costs (measured in dollars per ton of SO_2), the regulation excludes coals where the process yield required to remove the mandated fraction of sulfur falls too low. The precise formulation of the "regulation" is:

1. All coals must be subjected to a degree of preparation resulting in at least an X percent removal of sulfur (called the minimum sulfur removal) from the seam-quality coal Btu. Sulfur content is to be measured in pounds per million Btu.

2. Any coal for which an X percent removal would entail a process (weight) yield of less than Y percent (the minimum yield) need be washed only such that the resulting process yield is Y percent.

3. Any coal subject to part 2, above, for which a Y percent process yield would lead to a sulfur removal of less than Z percent (the threshold removal) is exempt from the washing requirement.

The meaning of the regulation is demonstration in Figure C-9, which shows basic washability curves for three coals. The vertical axis shows the percentage of sulfur removal as a function of the process yield. The minimum removal, minimum yield and threshold yield are shown. Coal 1, broadly speaking a washable coal, would be covered by part 1 of the formulation, forcing a minimum sulfur removal. Note that the regulation would not force washing to a degree suggested by the intersection of the minimum removal line and the washability curve. Rather, the whole section of the washability curve above the minimum sulfur removal would be permissible. The actual degree of washing would be determined by the least-cost solution of the coal supply module.

Coal 2 is slightly less washable than coal 1 and would be covered by part 2. The permissible section of the curve lies to the right of the minimum yield line. The washability curve for coal 3 lies below the threshold sulfur removal level at yields greater than the specified minimum. Therefore, it would be exempt from a mandatory washing requirement. The whole length of its washability curve would be permissible.

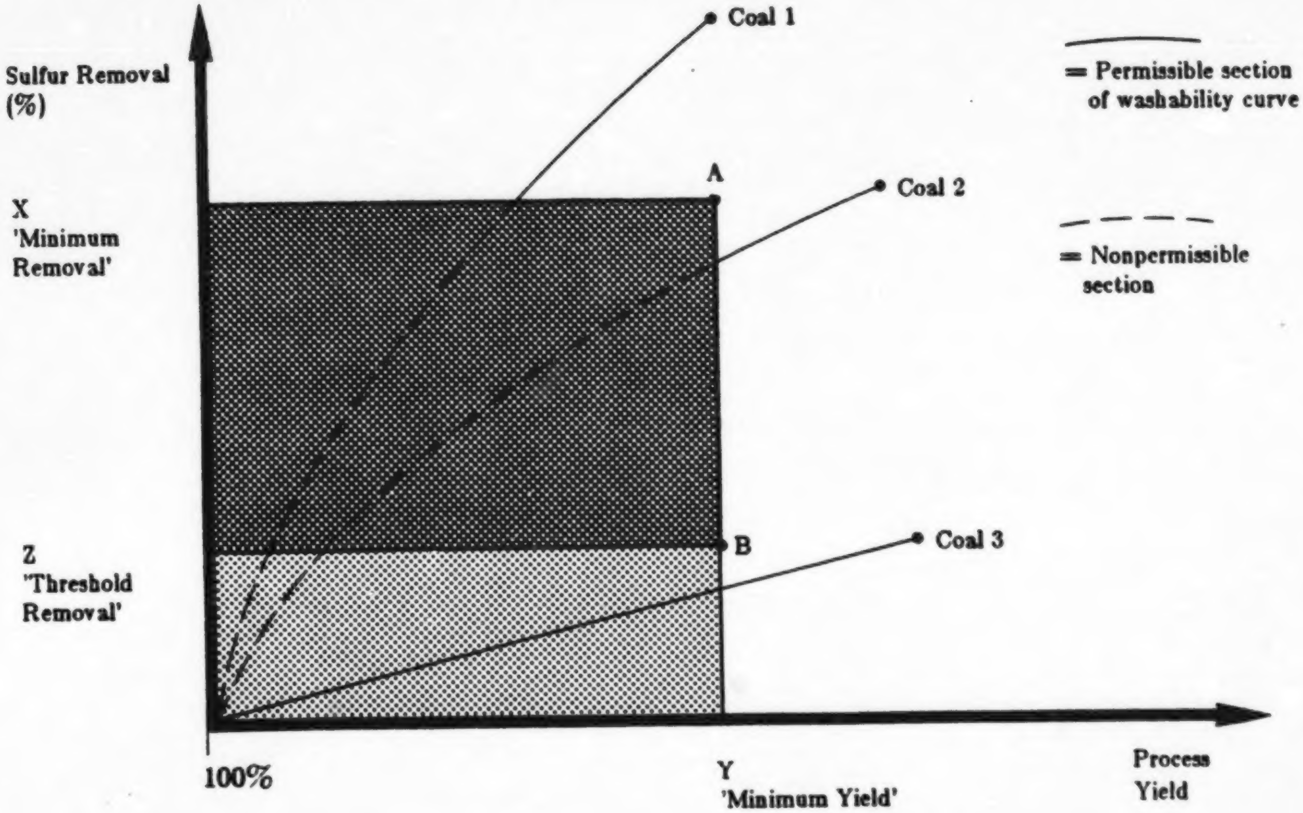
This formulation helps catch the worst examples of impracticable washing being forced on certain unsuitable types of coal. Another attractive feature of this formulation is that some undesirable consequences of a mandatory washing requirement may be captured. The types of coal that would be hardest hit can be identified. Probably more important, it is possible for the AUSM to show sulfur emissions increasing with a washing requirement because switches to cheaper, dirtier coals might result.

Three parameters used in the formulation may be specified by the AUSM user. Default values for a mandatory washing regulation are "hardwired" in to the coal supply module:

1. Minimum sulfur removal - 20%
2. Minimum weight yield - 75 %
3. Threshold sulfur removal - 10%

Note that coals such as sub-bituminous and lignite, for which only Level 1 washing is allowed, are completely exempt from this regulation.

Figure C-9
GRAPHICAL INTERPRETATION OF MANDATORY WASHING "REGULATION"



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